D.P.U. 92-214

Petition of Eastern Utilities Associates Systems pursuant to Massachusetts General Laws c. 164, s. 69I, as amended, and 980 C.M.R. 1.00 et seq. seeking approval of the Long-Range Forecast and Resource Plan of Eastern Edison Company and Montaup Electric Company.

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I. INTRODUCTION

A. Background

Eastern Utilities Associates ("EUA" or the "Company") is an investor-owned electric utility and a registered holding company under the Public Utility Holding Company Act of 1935 (Exh. EUASC-1, at 1). EUA owns directly all of the shares of common stock of three electric utility operating companies: Eastern Edison Company ("Eastern" or "EECo") in Massachusetts, and Blackstone Valley Electric Company ("Blackstone") and Newport Electric Corporation ("Newport") in Rhode Island (id.). EUA owns all of the permanent securities of Montaup Electric Company ("Montaup"), a generation and transmission company that supplies electricity to Eastern, Blackstone and Newport, and to municipal and unaffiliated utilities for resale (id.).[1] Another generation company owned by EUA is EUA Ocean State Corporation, which owns 29.9 percent of the Ocean State Power generating station in Burrillville, Rhode Island (id.). EUA also owns all of the common stock of EUA Power, a New Hampshire corporation whose principal asset is its 12.1 percent ownership interest in the Seabrook Nuclear Generating Station located in Seabrook, New Hampshire (id.).[2]

In addition to the above utility companies, EUA owns EUA Cogenex Corporation, an energy management and cogeneration company, EUA Energy Investment Corporation, a subsidiary established to invest in and develop cogeneration, independent, and small power production facilities, and EUA Service Corporation, a service company that performs

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1 Montaup owns the majority of the EUA System's generating facilities and also makes arrangements for purchasing power from other sources, including long-term entitlements and economical short-term purchases and sales when appropriate (id.).

2 On February 28, 1991, EUA Power filed a voluntary petition in the United States Bankruptcy Court for the District of New Hampshire for protection under Chapter 11 of the Federal Bankruptcy Code (id.). Effective December 31, 1990, EUA deconsolidated EUA Power for financial reporting purposes (id.). The EUA system does not include any of EUA Power's ownership interest in Seabrook in the current or projected generating capability of the EUA system (id.).

engineering, planning, financial, accounting, and other services for other EUA companies (id.).

Eastern conducts electric business in two geographically separate areas in southeastern Massachusetts (id. at 2). The Brockton division of Eastern consists of seventeen communities located in the area surrounding the City of Brockton, serving a population of approximately 300,000 (id.). The Fall River division of Eastern consists of five communities located in and around the City of Fall River, serving a population of approximately 145,000 (id.). Blackstone and Newport conduct electric utility business in Rhode Island serving 11 communities with a combined population of approximately 278,000 (id.).

The historic coincident peak load of 887,700 KW for the EUA System and Newport occurred on July 27, 1989 (id.).[3] The EUA System's 1992 generating capability owned and purchased, less capacity sold, comprised a net capability of 1,133 megawatts ("MW") in the winter 1991/1992 power period, and 1,203 MW for the summer 1992 power period (id.). The EUA System companies are members of the New England Power Pool ("NEPOOL") and NEPOOL treats the EUA System as one consolidated participant (id.).

B. Procedural History

On May 1, 1992, EUA System, in accordance with G.L. c. 164, § 69I and 980 C.M.R. 1.00 et seq., filed its "Long-Range Forecast and Resource Plan" for the period 1992 through 2001 with the Energy Facilities Siting Council ("Siting Council").[4] The Hearing

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[3] Newport was not part of the EUA System on July 27, 1989. The combined EUA System (including Newport) peak of 878,230 KW occurred on July 19, 1991 (id.).

[4] On May 1, 1992, the Governor filed a reorganization plan with the Legislature to merge the functions of the Siting Council into the Department of Public Utilities ("Department"). The reorganization plan was allowed by the Legislature and was enacted as Chapter 141 of the Acts of 1992 ("Reorganization Act"). Under the Reorganization Act, the merger of the two agencies became effective September 1, 1992 (§55). Pursuant to the Reorganization Act, the Siting Council's review of electric company forecasts and supply plans will be performed by the Department (§12). Further, all petitions, hearings and other proceedings duly brought before, and all prosecutions and legal and other proceedings duly begun by the Siting Council

Officer issued a Notice of Adjudication and directed the Company to post and publish the notice in accordance with 980 C.M.R. 1.03(2).[5] On July 28, 1992, the Company submitted confirmation of publication and posting in accordance with the Hearing Officer's Order of Notice. There were no petitions to intervene in this proceeding.

The Siting Council conducted evidentiary hearings on July 28 and July 29, 1992. EUA presented two witnesses: Donald C. Ryan, supervisor of market planning and forecasting in the Company's integrated resource management department, and Kevin A. Kirby, director of the Company's integrated resource management department. The evidentiary record consists of six exhibits submitted by the Company, sixty-one exhibits submitted by the Department, and responses to five record requests. Briefs were not requested by the Hearing Officer.

C. Scope of Review

In the last review of the EUA System, the Siting Council approved the demand forecast of Eastern, and rejected the supply plan of Montaup. Eastern Utilities Associates System, 18 DOMSC 73, 76 (1988) ("1988 EUA Decision")[6]. The current filing is the Company's last demand forecast and supply plan filing before making its filing in accordance

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which were pending immediately prior to the effective date of the Reorganization Act, shall continue unabated and remain in force notwithstanding the passage of this act, and shall thereafter be completed before the Department (§ 46).

5 On August 22, 1991, the Siting Council had opened a docket, EFSC 91-33, to review the 1991 demand forecast and supply plan of EUA System. With the filing of EUA's 1992 demand forecast and supply plan, the Siting Council opened a new proceeding, EFSC 92-33, and closed the docket on EFSC 91-33 without review. Subsequent to the merger of the functions of the Siting Council into the Department, the docket was changed to D.P.U. 92-214.

6 In accordance with G.L. c. 164, § 69I, as amended by the Reorganization Act (§ 15), an electric or gas company shall not commence construction of a facility at a site unless the facility is consistent with the most recently approved long-range forecast or supplement thereto. In addition, no state agency shall issue a construction permit thereafter unless such site and facility conforms to the most recently approved long-range forecast.

with the integrated resource management ("IRM") process.[7] Because the Siting Council's previous review of the supply plan of Montaup resulted in a rejection, the Department will review EUA's Long-Range Forecast and Resource Plan as they pertain to both Eastern and Montaup.[8]

II. DEMAND FORECAST

A. Standard of Review

The regulations set out the specific filing requirements for electric company forecasts, and set out the basis for review of such forecasts. See 980 C.M.R. 7.03. The Department will evaluate forecasts by applying three criteria. First, a demand forecast is reviewable if it contains enough information to allow a full understanding of the forecasting methodology.

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7 The IRM process contemplated a coordinated review by the Siting Council and the Department of the procedures by which electric companies plan, solicit, and procure resources to meet their obligations to provide reliable electric service to ratepayers in a least-cost, least-environmental impact manner. On August 31, 1990, the Department issued an Order and final regulations for its portion of the IRM regulatory framework. D.P.U. 89-239 (1990), 220 C.M.R. 10.00, and on November 30, 1990, the Siting Council issued an Order and final regulations for its portion of the IRM regulatory framework. Final Order on IRM Rulemaking, 21 DOMSC 91 (1990), 980 C.M.R. 12.00.

Pursuant to the Reorganization Act, the Department jurisdiction extends over the entire IRM process for electric companies. On August 26, 1992, the Department, on its own motion, opened an investigation into the amendment of 220 C.M.R. 10.00 and issued an Order promulgating emergency regulations to incorporate the Siting Council's IRM regulations into the Department's IRM regulations. D.P.U. 92-191. On December 4, 1992, the Department issued its Order in D.P.U. 92-191 promulgating revised IRM regulations.

8 In situations where an electric company's previous supply plan filing had been approved and there were no unusual circumstances, the Siting Council's final pre-IRM review had been limited to a review of the demand forecast. See, Commonwealth Electric Company and Cambridge Electric Light Company, 22 DOMSC at 116 (1991) ("1991 CECo/CELCo Decision"); Northeast Utilities, 24 DOMSC 77 (1992) ("1992 NU Decision"). See also, Fitchburg Gas and Electric Company, 24 DOMSC 322 (1992) ("1992 Fitchburg Decision").

Second, a forecast is appropriate if the methodology used to produce the forecast is technically suitable to the size and nature of the utility that produced it. Finally, a forecast is reliable if the methodology provides a measure of confidence that its data, assumptions, and judgments produce a forecast of what is most likely to occur. 1992 Fitchburg Decision, 24 DOMSC at 328; 1988 EUA Decision, 15 DOMSC at 79.

B. Previous Demand Forecast Review

1. Previous Siting Council Directives

In the 1988 EUA Decision, the Siting Council approved Eastern Edison's demand forecast, but directed the Company in its next filing to:

(1) (a) demonstrate that it has reviewed other methodologies or indices for forecasting demand costs, and (b) demonstrate that the CPI-based methodology is appropriate, or implement a different methodology deemed appropriate in light of the Siting Council's concerns;

(2) reflect the results of the Joint Utility Monitoring Project ("JUMP") in its forecast of average use per appliance or demonstrate why incorporation of the JUMP results would not be appropriate;

(3) file an update on the development of its long-range econometric model;

(4) document all industrial energy forecast assumptions, including rationales for eliminating data or adding dummy variables;

(5) describe fully its methodology for forecasting internal-use energy requirements; and

(6) present a plan for improving its peak-load forecasting methodology. This plan should include (a) a comparative analysis identifying the strengths and weaknesses of the present methodology versus alternative methodologies, and (b) a time schedule for implementing methodological enhancements.

The Siting Council further directed the Company in all future filings to:

(7) file its short-range energy and peak load forecasts including a description of the methodology used to develop those forecasts; and

(8) provide tests of the sensitivity of the energy and peak load forecasts to major assumptions and parameters including (a) a quantitative analysis of uncertainties including forecasts of high-growth and low-growth scenarios, and (b) a description of the methodology used to prepare such forecasts.

The Department addresses the Company's response to: Directive One regarding demand costs in Section II.C.2., infra; Directive Two regarding JUMP results in Section II.C.3., infra; Directive Three regarding Eastern's long-range econometric model in Section II.C.3., infra; Directive Four regarding industrial forecast assumptions in Section II.C.5., infra; Directive Five regarding internal-use energy requirements in Section II.C.6., infra; Directive Six regarding peak load forecasting in Section II.D., infra; and Directive Eight regarding sensitivity tests in Section II.D., infra.

2. Compliance with Directive Seven Regarding the Company's Short-range Forecast

In the 1988 EUA Decision, 18 DOMSC at 99, the Siting Council noted that the Company had failed to provide a description of the methodology used to prepare its short-term energy and demand forecasts. In response to Directive Seven, the Company stated that, to prepare the short-term forecast, it used an econometric model that incorporated actual year-to-date energy and demand data, actual and forecasted economic data, and data reflecting the deviations of actual weather from normal weather (id.).[9] EECo indicated that it used the short-term forecast primarily for financial planning and budgeting purposes, but that it also updated the 1992 long-run forecast estimates using results from the short-term forecast (id.).

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[9] EECo stated that it obtained economic data for use in its short-term forecast from Data Resources, Incorporated ("DRI") (Exh. EUASC-4, Vol. 1, at C-58). EECo indicated that economic variables included in its short-term forecast models included real per capita income, manufacturing output, manufacturing productivity, and manufacturing employment (id.). EECo indicated that it obtained historic weather data from weather station of the National Oceanic and Atmospheric Administration ("NOAA") in Providence Weather Station (Exh. EUASC-1, Vol. 4, App. 7, at 2).

Based on the foregoing, the Department finds that the Company has complied with Directive Seven.

C. Energy Forecast

Eastern forecasted annual energy requirements by first preparing economic and demographic forecasts and an electricity price forecast, and then applying those forecasts in detailed end-use and econometric models (Exh. EUASC-1, Vol. 2, at 49-52). Eastern's energy forecasts are disaggregated by class of service for both of the Eastern's service areas (id.). The results of Eastern's energy forecasts are presented in Tables 1 and 2, infra.

1. Economic and Demographic Forecasts

a. Description

EECo stated that it developed forecasts of various economic and demographic variables (id., Vol. 4, App. 1, at 1), and that these forecasts were among the key drivers of Eastern's energy forecasts (id.; Exh. EFSC-D-1). EECo indicated that the forecasted economic and demographic variables included state and service area manufacturing and non-manufacturing employment, income, and population (Exh. EFSC-D-1).

To estimate employment and income levels for its service territories, the Company stated that it specified econometric models that measured the historical relationship between employment and income variables and certain exogenous variables (Exh. EUASC-1, Vol. 4, App. 1, at 1).[10] EECo indicated that it obtained historic and forecast values of state level employment and income data from DRI,[11] and service area data from various government agencies (id.).

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[10] The exogenous variables consisted primarily of corresponding state-level data, time trend variables, and binary variables (Exh. EUASC-1, Vol. 4, App. 1, at 1, 5-67).

[11] EECo stated that its economic and demographic forecasts incorporated data from DRI's September, 1991 Massachusetts and Rhode Island economic forecasts (Exh. EFSC-D-4).

i. Employment

Eastern indicated that it obtained service area employment data for the years of 1975 through 1990 from the Massachusetts Department of Employment Security (id.). EECo obtained historical Fall River and Brockton employment data relating to six non-manufacturing sectors: (1) finance, insurance and real estate; (2) services; (3) wholesale and retail trade; (4) regulated industries; (5) construction; and (6) local, state and federal government (id., Vol. 4, App. 1, at 39, 60). EECo also indicated that it obtained employment data for these service areas relating to 20 manufacturing industries, particularly Standard Industrial Classifications ("SICs") 20-39 (id. at 1).

Eastern stated that it forecasted non-manufacturing employment in the Brockton service area to increase at a compound annual growth rate of 2.2 percent, from about 75,000 in 1991 to about 93,000 in 2001 (id. at 37). EECo indicated that it forecasted manufacturing employment in the Brockton service area to increase at a compound annual growth rate of 0.9 percent, from about 15,000 in 1991 to about 16,000 in 2001 (id.).

EECo stated that it forecasted non-manufacturing employment in the Fall River service area to increase at a compound annual growth rate of 1.6 percent, from about 30,000 in 1991 to about 35,000 in 2001 (id. at 57). Eastern stated that it forecasted manufacturing employment in the Fall River service area to increase at a compound annual growth rate of 0.1 percent, from about 14,300 in 1991 to about 14,500 in 2001 (id.).

ii. Population

EECo stated that historical estimates and forecasts of population for the Brockton and Fall River service areas were derived from projections provided by the Massachusetts Institute for Social and Economic Research ("MISER"),[12] and from various sets of U.S. Census Bureau ("Census Bureau") data (id. at 1).

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12 EECo stated that its population forecasts incorporated data from MISER's February, 1991 forecast (Exh. EFSC-D-4).

EECo indicated that historical service area population estimates were derived for 1975 through 1979 through interpolation between Census Bureau estimates for the years 1974, 1976, 1978 and the official 1980 Census Bureau figure (id.). Historical population estimates for the years 1981 through 1989 were obtained by interpolating between the official 1980 and 1990 Census Bureau figures (id.).

Eastern stated that MISER also provided forecasts of Brockton and Fall River population for the years 1995 and 2000 (Exh. EFSC-D-4, at 19, 24), and that through both interpolation and extrapolation, the Company developed city-level forecasts of population for the years 1991 through 2015 (Exh. EUASC-1, Vol. 4, App. 1, at 1, 37, 57).

EECo stated that it forecasted population in the Brockton service area to remain at about 300,000 throughout the forecast period (id. at 37), and in the Fall River service area, to increase at a compound annual growth rate of 0.2 percent, from about 145,000 in 1991 to about 148,000 in 2001 (id. at 57).

iii. Real Per Capita Income

EECo stated that estimates of Bristol and Plymouth County real per capita income for the years 1975 through 1989 were provided by the U.S. Bureau of Economic Analysis (id. at 1). EECo indicated that it used the U.S. Bureau of Economic Analysis estimates for Bristol and Plymouth Counties as proxies of real per capita income for its Brockton and Fall River Service areas, respectively (id. at 2).[13]

To develop a forecast of real per capita income for its service areas, the Company indicated that it used regression analysis to estimate the relationship between the county per capita income data and statewide real per capita income data (id. at 2, 34, 56). Forecast

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[13] EECo stated that its Fall River service area contained about 28.6 percent of 1991 Bristol County population (Tr. 1, at 7; Exh. EFSC-D-8), and that its Brockton service area contained approximately 69.0 percent of the 1991 Plymouth County population (Exh. EFSC-D-8). EECo added that it was not aware of any historical per capita income data set specific to its service areas, and that it believed that the county data was very representative of its service areas (Tr. 1, at 7).

Massachusetts per capita income data for the forecast was provided to Eastern by DRI (Exh. EFSC-D-4, at 9).

EECo stated that it forecasted real per capita income in the Brockton service area to increase at a compound annual growth rate of 1.5 percent, from about $5,500[14] in 1991 to about $6,400 in 2001 (id. at 37).

EECo indicated that it forecasted real per capita income in the Fall River service area to increase at a compound annual growth rate of 1.7 percent, from about $6,100 in 1991 to about $7,200 in 2001 (id. at 57).

b. Analysis and Findings

In the past, the Siting Council approved economic and demographic forecasting methodologies consisting of econometric models that analyze the relationship between territory-specific historical data and corresponding statewide forecast projections. See Boston Edison Company, 24 DOMSC 125, 160 (1992) ("1992 BECO Decision"). In fact, the Siting Council accepted a similar methodology employed previously by Eastern. 1988 EUA Decision, 18 DOMSC at 81, 82. In addition, Eastern's use of statewide data inputs supplied by DRI is consistent with input data approved in a number of other cases. 1992 BECO Decision, 24 DOMSC at 160; 1991 CECo/CELCo Decision, 22 DOMSC at 126; Massachusetts Municipal Wholesale Electric Company, 20 DOMSC 1, 14 (1990) ("1990 MMWEC Decision"). The Siting Council also has accepted the use of data inputs supplied by DRI in the use of economic and demographic forecasts prepared previously by Eastern. 1988 EUA Decision, 18 DOMSC at 82; Eastern Utilities Associates System, 14 DOMSC 41, 53-58 (1986) ("1986 EUA Decision").

The Department notes that Eastern, in most cases, has employed methodologies and data in its economic and demographic forecasts that are reviewable, appropriate and reliable. However, the Department also notes one weakness in the instance of historical estimates of

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[14] EECo indicated that it presented real per capita income data in 1970 dollars (EUASC-1, Vol 4, App. 1, at 4).

Fall River real per capita income. Here, the Company used data sets that may not reflect adequately pertinent characteristics of its customers. Essentially, Eastern relies on historic data for Fall River real per capita income that consists of a low percentage of service area customers. While recognizing that it is sometimes difficult for a company to obtain data sets that precisely approximate pertinent characteristics of its service area population, nonetheless, the Department encourages Eastern to continue to refine and improve the representativeness of its data to the greatest extent possible.

Based on the foregoing, the Department finds that Eastern's methodology for forecasting economic and demographic factors is reviewable, appropriate, and reliable

2. Electricity Price Forecast

a. Description

Eastern stated that it developed a forecast of electricity price for each customer class within each of its retail subsidiaries (Exh. EUASC-1, Vol. 4, App. 2, at 1, 2). EECo indicated that an electricity price forecast is necessary since price of electricity has a "major impact" on electricity consumption (id. at 1).

EECo stated that development of its electricity price forecast depends upon inputs relating to energy and peak forecasts, and that therefore, energy, peak and price forecasts were developed simultaneously (id.).

EECo indicated that it separated electricity price into three major cost components: (1) a "system demand cost" component, (2) an "energy cost" component, and (3) a "distribution cost" component (id.; Tr. 1, at 26).

i. System Demand Costs

EECo stated that projections of Montaup system demand costs were based on two major subcomponents and several minor subcomponents (Exh. EUASC-1, Vol. 4, App. 2, at 1). The two major subcomponents, accounting for about 70 percent of total demand costs, were base costs and purchased power demand expense (id.). EECo stated that base costs were taken from Montaup's M-13 filing with the Federal Energy Regulatory Commission, and that they consisted of non-fuel production expenses from wholly-owned power plants, transmission expenses, and Montaup's administrative and general expenses (id.). For its electricity price forecast, Eastern escalated its base costs at the Gross National Product ("GNP") inflation rate (id.).[15]

EECo indicated that Montaup's purchased power demand expenses were calculated by reviewing Montaup's purchases from other utilities, determining contract expiration dates, and applying the GNP inflation rate to each contract cost (id.). EECo stated that the remaining system demand cost components, which accounted for approximately 30 percent of total system demand costs, consisted of return on debt and equity from EUA-owned units, taxes and depreciation from EUA-owned units, Seabrook Unit 2 abandonment expenses, demand-side management program costs, and transmission and generating unit additions (id.). Revenues from contract sales were subtracted from total demand costs (id.).

Eastern stated that EUA allocated demand costs among its retail subsidiaries according to a ratio of each subsidiary's average annual peak load to that of total Eastern system annual peak (id. at 3).

ii. Energy Costs

Eastern forecasted energy costs, that consisted primarily of fuel costs, using its production cost simulation model, UPLAN 3 ("UPLAN") (id.).[16] EECo stated that it used UPLAN to simulate an "own-load dispatch" that assumes only units within Eastern's supply portfolio would be dispatched to meet Eastern's load (id.).[17] EECo indicated that oil and

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[15] EECo obtained the GNP inflation rate from a 1991 DRI forecast (Exh. EFSC-D-4, at 27).

[16] EECo described UPLAN 3 as "a probabilistic production cost model that economically fits the most optimum mix of available generation capacity under a cumulative probability curve on a monthly basis." (Exh. EUASC-1, Vol. 4, App. 2, at 6).

[17] EECo indicated that, even though this simulation differs from actual NEPOOL economic dispatch practices, NEPOOL bills participants as though they had dispatched on an "own-load" basis. (Exh. EUASC-1, Vol. 4, App. 2, at 3). EECo

coal costs used in the simulation were inflated by fuel specific escalation rates obtained from DRI (id. at 6). Nuclear fuel costs were forecasted by the lead participant of each nuclear plant (id.). EECo indicated that the result of its production cost simulation was a forecast of total fuel costs for the EUA system (id.).

Eastern stated that EUA allocated energy costs among its retail subsidiaries according to a ratio of each subsidiary's annual energy requirements to total EUA system energy sales (id. at 9).

iii. Total Wholesale Cost

EUA stated that it developed total wholesale cost projections for its retail subsidiaries by summing energy and demand costs of the subsidiaries (id. at 10). EECo divided total costs by the subsidiaries' projected energy sales to obtain a cents per kilowatthour ("KWH") bulk power supply cost (id.). The forecast was then calibrated to 1991 actual energy service cost by dividing actual 1991 electricity prices by forecasted 1991 electricity prices (id. at 13). EECo forecasted "real" electricity prices in each of Eastern's classes of service to decline slightly over the forecast period (id. at 15).

iv. Distribution Costs

Eastern indicated that it inflated forecast distribution costs, which consisted of non-power supply related expenses of EUA's distribution companies, based on the historical relationship between the annual increase in these expenses and the Consumer Price Index ("CPI") growth rate as forecasted by DRI (id. at 6).[18] EECo stated that distribution costs

stated that "own-load" dispatch therefore represented a valid means of estimating future energy costs (id.).

[18] EECo indicated that it conducted an analysis comparing the historical trend of Montaup's distribution costs with the historical trend of various inflation indices, including the CPI, the Handy-Whitman index, the Producer Price Index, and the Gross National Product Price Deflator (Exh. EUASC-4, Vol. 1, App. 3B at 1). EECo found that the historical CPI yielded the compound growth rate that was closest to the historical compound growth rate of the Company's distribution costs (id. at 5).

were allocated to each class of service according to the 1991 average cost of service by class (id. at 6, 10).

b. Analysis and Findings

The Department notes several strengths of the Company's price forecast. First, Eastern breaks down total costs into identifiable components: demand, energy, and distribution. Second, the Company allocates costs among its retail subsidiaries in a manner proportionate to the subsidiaries' requirements. Third, Eastern calibrates forecast prices to actual prices in a manner that contributes to forecast reliability. Fourth, the Company projects electricity costs separately for each class of service. Finally, the Company appropriately uses a production cost model to develop cost data specific to its own operations. In the past, the Siting Council approved similar methodologies for forecasting electricity price. 1992 NU Decision, 24 DOMSC at 88, 89; Northeast Utilities, 17 DOMSC 1, 9 (1988).

Based on the foregoing, the Department finds that Eastern's methodology for forecasting the price of electricity is reviewable, appropriate, and reliable.

c. Compliance with Directive One Regarding the Company's Electricity Price Forecast

In the 1988 EUA Decision, 18 DOMSC at 84, the Siting Council noted that a weakness in Eastern's electricity price forecast was in the Company's reliance on the CPI to forecast demand and distribution costs. The record in this case indicates that the Company (1) conducted an analysis that justified the use of an adjusted CPI growth rate to forecast distribution costs; and (2) inflated base costs and purchased power demand expenses (major components of the Company's demand costs) by the GNP inflation rate.

Based on the foregoing, the Department finds that Eastern has complied with Directive One.

3. Residential Energy Forecast

a. Description

Eastern's residential class energy sales accounted for 42.0 percent of Eastern's total retail sales in 1991 (Exh. EUASC-1, Vol. 3, at C-8). Eastern's residential sales grew from 827.2 gigawatthours ("Gwh") in 1978 to 1,021.0 Gwh in 1991, a compound growth rate of 1.6 percent (id.). Eastern forecasted unadjusted residential sales to grow from 1,038.6 Gwh in 1992 to 1,227.8 Gwh in 2001, a compound growth rate of 1.9 percent (id.).[19] Eastern's forecasted energy sales are presented in Table 2.

Eastern used an end-use model to forecast energy consumption of 19 appliances (id., Vol. 2, at 52; Vol. 4, App. 3, at 79, 81).[20] Eastern calculated consumption for each residential end-use as the product of (1) the number of appliances, and (2) the annual consumption per appliance (id., Vol. 2, at 58). EECo stated that it was necessary to predict the number of residential customers, and appliance ownership or saturation levels to produce the residential sales forecast (id. at 58, 59).[21] EECo further stated that it was necessary to adjust consumption per appliance figures to account for the effects of electricity price, income, efficiency standards, and household size (id. at 59). Model inputs included

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19 The unadjusted residential energy sales figures do not reflect the projected savings from Company-sponsored DSM programs (Exh. EUASC-1, Vol. 2, at 53). If projected DSM savings are included, the forecasted residential sales figures would be 1,029.2 Gwh in 1992 increasing to 1,167.4 Gwh in 2001, a compound growth rate of 1.4 percent (Exh. EUASC-1, Vol. 3, at C-10).

20 Eastern disaggregated its residential energy forecast into the following end-uses: (1) electric ranges; (2) frost-free refrigerators; (3) standard refrigerators; (4) frost-free freezers; (5) standard freezers; (6) dishwashers; (7) clothes washers; (8) clothes dryers; (9) controlled water heaters; (10) uncontrolled water heaters; (11) microwave ovens; (12) color television sets; (13) black and white television sets; (14) lighting; (15) room air conditioners; (16) central air conditioners; (17) electric space heating systems; (18) fossil fuel auxiliaries; and (19) miscellaneous (Exh. EUASC-1, Vol. 4, App. 3, at 74, 75).

21 "Saturation" refers to the percentage of customers owning a particular appliance.

historical and projected economic, demographic and electricity price data and customer survey data (id. at 59-62).

EECo's witness, Dr. Ryan, indicated that a number of changes have been incorporated into the residential energy forecasting methodology since the previous review by the Siting Council (Tr. 1, at 38-39). First, the Company stated that data obtained through JUMP was incorporated into the Company's estimates of use per appliance (id.).[22] Second, the Company indicated that it developed long-range econometric models to predict service-area-specific price and income elasticities, and that it incorporated these elasticities into the residential forecast (id. at 39). Third, the Company stated that it estimated econometric models to predict electric space heating and controlled water heating saturations (id. at 40). Finally, Dr. Ryan stated that the Company developed linear probability models to predict saturations of appliances other than electric space heat and controlled water heaters based on income, persons per household, and other selected factors (id.).

A description and analysis of the major components of Eastern's residential energy forecast is provided below.

i. Number of Residential Customers

Eastern stated that its forecasts of residential customers were based on DRI's forecast of Massachusetts housing stocks (Exh. EUASC-1, Vol. 4, App. 3, at 1, 4). Eastern forecasted the number of residential customers in the Brockton service area using regression analysis relating the number of Brockton residential customers to the Massachusetts housing stock and a time trend (id. at 1, 4). EECo indicated that the number of residential customers

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22 JUMP was a collaboration among Massachusetts utilities to monitor the connected load and hours of operation for uncontrolled water heaters, frost-free refrigerators, electric ranges and electric clothes dryers (Exh. EUASC-3, Vol. 1, at B-23; Tr. 1, at 42). These appliances accounted for 39 percent and 41 percent, respectively, of the 1991 residential energy use in the Brockton and Fall River service areas (Exh. EUASC-1, Vol. 4, App. 3, at 79, 81).

in the Fall River service area was forecasted to grow at the same rate as DRI's forecast of Massachusetts housing stocks (id. at 1).[23]

EECo's filing included a statistical justification of the Brockton residential customer model (id. at 3). However, the filing does not include a statistical analysis of the historical relationship between the growth rate of the Fall River residential customer count and the Massachusetts housing stock.[24]

ii. Number of Residential Appliances

Eastern stated that the number of residential appliances was equal to the product of residential customers and appliance saturations (Exh. EUASC-1, Vol. 4, App. 3, at 47). EECo indicated that it forecasted most appliance saturations of residential customers in the Blackstone Valley and Eastern Edison service areas using econometric and linear probability models and cross sectional data obtained from the results of a residential survey conducted by the Company in 1989 (id., Vol. 2, at 59; Vol. 4, App. 3, at 45).[25]

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23 EECo indicated that, in 1991, the Brockton service area contained about 103,000 residential customers, and the Fall River service area contained about 51,000 residential customers (Exh. EUASC-1, Vol. 4, App. 3, at 7).

24 According to Eastern, the econometric model used to predict the number of residential customers in the Brockton service area showed considerable statistical strength (Exh. EUASC-1, Vol. 4, App. 3, at 3). For example, the Company indicated that the Brockton residential customer model produced an R-squared of .99 (id.). (R-squared is a measure of the amount of variation in the dependent variable which is explained by the variation in the independent variables. R-squared values range between 0.00 and 1.00, where 0.00 indicates no variation explained by the independent variables and where 1.00 indicates complete explanation by the independent variables.) However, the Company indicated that, in the case of the Fall River service area, the same model produced poor statistical results and was therefore abandoned (Exh. EFSC-D-20).

25 Eastern's 1989 residential survey was the chief source of data used in most of the appliance saturation models (Exh. EUASC-1, Vol. 4, App. 3, at 45). Eastern stated that the survey was designed to provide (1) a detailed inventory of end-uses used by Eastern residential customers, (2) an analysis of energy conservation measures taken by residential customers over the five-year period prior to the mailing of the survey,

EECo indicated that its electric space heating saturation model used a time trend and real electricity prices as predictor variables (id). A discussion of Eastern's electricity price forecast is contained in Section II.C.2., supra. EECo stated that saturation of fossil fuel auxiliaries[26] was calculated as one minus the electric space heating forecast (id). EECo assumed lighting and miscellaneous category saturations to be 100 percent throughout the forecast period (id.).

EECo forecasted other appliance saturations using linear probability models estimated across all households in the Brockton and Fall River service areas based upon 1989 residential survey responses (Exh. EUASC-1, Vol. 2, at 62). Explanatory variables used in these models included income, presence of electric space and water heating, gas availability, service area, and persons per household (id., Vol. 4, App. 3, at 46).[27] EECo obtained 1989 mean values of the foregoing variables from survey responses, and values for all other historical and forecast years from actual time series data or forecasts of these data (id).

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and (3) housing type occupancy and demographic characteristics of the Eastern residential customer base (Exh. EFSC-D-23, at 4). EECo stated that the 1989 residential survey was mailed to a random sample of 2,400 Eastern customers, and that the response rate was nearly 65 percent from Brockton and Fall River samples (id., App. F; Tr. 1, at 43). EECo indicated that it designed and planned to distribute an updated residential survey instrument during 1992, and that it anticipated that the results of the new survey would be available for use in the 1994 long-range residential forecast (Tr. 1, at 45; Exh. EFSC-D-23, at 1).

[26] "Fossil fuel auxiliaries" are electric motors connected to fossil fueled residential heating systems.

[27] Eastern stated that the persons per household forecast was obtained by dividing the service area population forecast by the residential customer forecast (Exh. EUASC-1, Vol. 2, at 59). See Section II.C.1.b., supra, for a discussion of the Company's service area population forecasts, and Section II.C.3.a, supra, for a discussion of the Company's residential customer forecast.

iii. Annual Use Per Appliance

Eastern stated that annual energy use for a particular appliance group was calculated as the product of (1) the number of appliances in the group, (2) the appliance's connected load (i.e., the appliance's instantaneous demand in watts), and (3) the appliance's annual hours of operation (Exh. EUASC-1, Vol. 2, at 62). EECo forecasted annual use per appliance by (1) estimating connected load and annual hours of operation for the base year of 1980, and (2) estimating connected load and annual hours of operation in subsequent years by adjusting the base year forecast for expected changes in electricity price, appliance efficiency, household size, and household income (Exh. EUASC-1, Vol. 2, at 62-64).

EECo stated that it developed base year estimates of connected load and hours of operation from data obtained through the JUMP and NEPOOL (id. at 62; Exh. EUASC-3, Vol. 1, at B-23).[28] For each appliance, the Company forecasted: (1) price elasticities based on the output from long-term econometric models of residential electricity demand in the Blackstone, Brockton, and Fall River service areas; (2) appliance efficiency trends based on NEPOOL estimates; (3) the effects of household size based on the Company's forecasts of service area population and residential customers; and (4) income elasticities based on the output from service area-specific long-term econometric models of residential electricity demand (Exh. EUASC-1, Vol. 2, at 62-64).

b. Analysis and Findings

Eastern's forecast of the number of residential customers in the Brockton service area is based upon reasonable statistical projections. However, the Company failed to justify the historical relationship between growth of the Massachusetts housing stock and the Fall River customer count. Accordingly, in order for the Department to approve the residential forecast

28 EECo stated that JUMP data was used for estimating hours of operation and connected loads of uncontrolled electric water heaters, frost-free refrigerators, electric ranges, and electric clothes dryers (Exh. EUASC-1, Vol. 2, at 62). EECo indicated that data pertaining to energy use for remaining residential end-uses were obtained from NEPOOL (id.).

in the Company's next filing, Eastern must furnish a full justification of continued use of its present methodology or adequate statistical justification of any new data set used as a predictor of Fall River residential customer. For the purposes of this review, the Department accepts Eastern's forecast of residential customers.

Eastern's forecast of the number of residential appliances exhibits several notable strengths. First, the forecast is disaggregated by end-use and service area. In addition, the forecast is based on survey results that provided detailed, service-area-specific, and recent information regarding the residential appliance inventory and customer characteristics. Further, the Company has indicated that it will undertake a new residential survey prior to submittal of its next forecast filing. Accordingly, the Department accepts Eastern's forecast of the number of residential appliances.

Eastern's forecast of annual use per end use also exhibits notable strengths. Specifically, the Company adjusted base year estimates of connected load and hours of operation according to service area-specific price elasticities, appliance efficiency trends obtained from NEPOOL, household size, and household income. Based on the foregoing, the Department accepts Eastern's forecast of annual use per appliance.

The Department has accepted Eastern's forecasts of (1) number of residential customers, (2) the number of residential appliances, and (3) annual use per appliance. The Department recognizes that the Company's residential forecast uses a methodology that is disaggregated across a broad range of appliances, and which accounts for many of the chief determinants of residential energy consumption.

Based on the foregoing, the Department finds that Eastern's methodology for forecasting residential energy requirements is reviewable, appropriate, and reliable.

c. <u>Compliance with Directives Two and Three Regarding the Company's Residential Energy Forecast</u>

In the <u>1988 EUA Decision</u>, 18 DOMSC at 87, the Siting Council noted its concern about the Company's reliance on regional appliance use data supplied by NEPOOL. The Siting Council's concern was based on the possibility that the Eastern service areas may exhibit different characteristics than those reflected in the NEPOOL data. Id. The record in this case indicates that the Company's forecast of annual appliance use incorporated service-area-specific data generated by Eastern's long term econometric models (Exh. EUASC-1, Vol. 2 at 62-64). In addition, the forecast incorporated data generated by JUMP (id.). Based on the foregoing, the Department finds that Eastern has complied with Directives Two and Three regarding the Company's residential energy forecast.

4. Commercial Energy Forecast

a. Description

Eastern's commercial class energy sales accounted for 45.1 percent of Eastern's total retail sales in 1991 (Exh. EUASC-1, Vol. 3, at C-8). Eastern's commercial sales grew from 738.6 Gwh in 1978 to 1,096.1 Gwh in 1991, a compound growth rate of 3.1 percent (id.). Eastern forecasted unadjusted commercial sales to grow from 1,127.6 Gwh in 1992 to 1,441.5 Gwh in 2001, a compound growth rate of 2.8 percent (id.).[29] Eastern's forecasted energy sales are presented in Table 2.

Eastern has adopted a new commercial energy forecasting methodology since the previous Siting Council review. In the past, the Company used an econometric model to predict aggregate commercial sector consumption (Tr. 1, at 53). The previous model used historic values of KWH per employee, made adjustments for price effects, and projected future consumption with a time trend (id.). EECo currently uses the Commercial Energy Demand Model System ("CEDMS") that was developed by Jerry Jackson Associates ("JJA") (Exh. EUASC-1, Vol. 2, at 67). Eastern's methodology projected commercial sector energy

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29 The unadjusted commercial class energy sales figures do not reflect the projected savings from Company-sponsored DSM programs (Exh. EUASC-1, Vol. 2, at 53). If projected DSM savings are included, the forecasted commercial energy sales figures would be 1,117.7 Gwh in 1992 increasing to 1,343.5 Gwh in 2001, a compound growth rate of 2.1 percent (id. at C-10).

usage of eight end-uses in ten building types (id., Vol. 4, App. 4, at 1).[30] Essentially, commercial energy use is represented in the model as the product of (1) equipment stock, (2) the maximum energy consumption of that equipment (Energy Use Index or "EUI"), and (3) equipment energy utilization rates (id., Vol. 2, at 67). EECo stated that the key drivers of the commercial energy forecast are Eastern's service area economic and demographic forecasts, and the commercial electricity price forecast (id., Vol. 4, App. 4, at 1).

EECo stated that, because most commercial end-uses are designed on the basis of floor space served, equipment stock was measured as a function of the stock of commercial floor space in Eastern's service areas (id. at 1, 67, 68). EECo indicated that JJA developed floor space estimates for each building type using employment and population data from the Company's service area economic and demographic forecasts (id., Vol. 2, at 68). See Section II.C.1., supra, for a description of Eastern's economic and demographic forecasts.

EECo stated that JJA developed an EUI for each building type which reflected end-use energy consumption per square foot of commercial floor space (id. at 67, 68). The EUIs were developed using Company data pertaining to the number of commercial customers and sales, service area floor stock estimates, and audit results from New England and New York utilities (id. at 68; Exh. EFSC-D-34).

EECo indicated that measures of energy intensity, or utilization rates, were developed for both new and existing equipment (Exh. EUASC-1, Vol. 2, at 68-69; Tr. 1, at 56). With respect to new equipment, the Company stated that CEDMS simulated equipment choice based equipment costs, operating costs, and payback requirements of sample commercial firms (Tr. 1, at 57; Exh. EUASC-1, Vol. 2, at 68). EECo indicated that utilization of existing equipment was modeled on the basis of estimates of service area price elasticities

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[30] EECo indicated that the end-uses represented in the CEDMS model were (1) space heating, (2) air conditioning, (3) ventilation, (4) water heating, (5) cooking, (6) refrigeration, (7) lighting, and (8) miscellaneous. (Exh. EUASC-1, Vol. 4, App. 4, at 1). The ten building types represented in the model were (1) office, (2) restaurant, (3) retail, (4) grocery, (5) warehouse, (6) elementary/secondary school, (7) college/university, (8) health care, (9) hotel/motel, and (10) miscellaneous (id.).

(Exh. EUASC-1, Vol. 2, at 68-69). The price elasticities were estimated using Eastern's long-term econometric model (Tr. 1, at 65).

Eastern indicated that JJA used electricity price data, state natural gas and oil price indices, and heating and cooling degree day data to calibrate the CEDMS model to actual service area commercial sector energy usage (Exh. EUASC-1, Vol. 2, at 69).[31]

b. Analysis and Findings

In the 1988 EUA Decision, 18 DOMSC at 15, 16, the Siting Council rejected the Company's commercial energy forecast because of a lack of disaggregation in the commercial class database. Eastern's subsequent modifications to its commercial energy forecasting methodology represents a significant effort on the part of the Company to enhance its forecast. Eastern now employs a sophisticated commercial energy forecasting methodology that analyzes energy consumption of eight end-uses in ten building types. The methodology incorporates current, service area-specific data sets pertaining to employment, population, commercial sector electricity price, and price elasticity. In the past, the Siting Council has approved similar end-use commercial energy forecasting methodologies that incorporate territory-specific input data. 1992 NU Decision, 24 DOMSC at 106; 1992 BECo Decision, 24 DOMSC at 206. Based on the foregoing, the Department finds that Eastern has established that its commercial energy forecast is reviewable, appropriate, and reliable.

31 EECo stated that (1) historical commercial electricity price data were obtained from in-house records, (2) projected prices were obtained from Eastern's electricity price forecast, (3) historical fuel price data were obtained from the U.S. Department of Energy's State Energy Data System, (4) forecasted fuel price data were obtained from DRI, and (5) historic weather data were obtained from NOAA's Providence weather station (Exh. EUASC-1, Vol. 4, App. 4, at 2; Exh. EFSC-D-34).

5. Industrial Energy Forecast

a. Description

Eastern's industrial class energy sales accounted for 12.2 percent of Eastern's total retail sales in 1991 (Exh. EUASC-1, Vol. 3, at C-8). Eastern's industrial sales grew from 286.3 Gwh in 1978 to 297.1 Gwh in 1991, a compound growth rate of 0.3 percent (id.). Eastern forecasted unadjusted industrial sales to grow from 301.4 Gwh in 1992 to 358.2 Gwh in 2001, a compound growth rate of 1.9 percent (id.).[32] Eastern's forecasted energy sales are presented in Table 2.

EECo stated that it has modified its methodology for forecasting industrial energy sales since the previous Siting Council review (Tr. 1, at 65). Previously, Eastern used regression analyses to forecast average annual industrial energy intensiveness by two digit SIC code, and adjusted the forecast for price elasticity factors that were obtained from NEPOOL. 1988 EUA Decision, 18 DOMSC at 92, 93.

In this filing, Eastern forecasted industrial energy sales in the Brockton and Fall River service areas using newly-specified econometric models that related energy use in 19 separate SIC categories[33] to one or more explanatory variables (Exh. EUASC-1, Vol. 4, App. 5, at 1, 44-46, 59-61). EECo assumed total service area industrial energy usage to be equal to the sum of the individual SIC category usages (id. at 43-45, 59-61).

EECo stated that explanatory variables included service area manufacturing employment, state manufacturing employment, state manufacturing output, state

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32 The unadjusted industrial class energy sales figures do not reflect the projected savings from Company-sponsored DSM programs (Exh. EUASC-1, Vol. 2, at 53). If projected DSM savings are included, the forecasted industrial energy sales figures would be 300.4 Gwh in 1992 increasing to 354.4 Gwh in 2001, a compound growth rate of 1.9 percent (id., Vol. 3, at C-10).

33 Eastern Edison forecasted energy sales to the following manufacturing industries: (1) food and kindred; (2) textiles; (3) apparel; (4) lumber; (5) wood products; (6) paper; (7) printing; (8) chemical; (9) petroleum; (10) rubber and plastics; (11) leather; (12) stone, clay, glass, and concrete; (13) primary metals, (14) fabricated metals; (15) non-electrical machinery; (16) electrical machinery; (17) transportation; (18) scientific instruments; and (19) miscellaneous.

manufacturing productivity, previous period energy use, real industrial class electricity price, real natural gas price, the ratio of electricity price to gas price, and a time trend (id. at 1). EECo noted that binary variables were used in many of the models to explain structural changes not adequately reflected by the available explanatory variables (id.).[34]

b. Analysis and Findings

The Department notes that Eastern has enhanced its industrial energy forecasting methodology since the previous Siting Council review through the incorporation of a range of economic and price variables to explain industrial energy consumption. Eastern's use of econometric modeling to predict energy use in 19 distinct manufacturing categories by service area is a reasonable methodology for a company of the size and resources of Eastern. The Siting Council has approved a similar methodology in the past. 1991 CECo/CELCo Decision, 22 DOMSC at 149-150. Accordingly, the Department finds that Eastern has established that its industrial energy forecast is reviewable, appropriate and reliable.

c. Compliance with Directive Four Regarding the Company's Industrial Energy Forecast

In the previous review of the Company's industrial energy forecast, the Siting Council directed the Company to fully document all industrial energy forecast assumptions, indicating rationales for eliminating data or adding binary variables. 1988 EUA Decision, 18 DOMSC at 93. The record in this case indicates that Eastern (1) has furnished documentation of all industrial energy forecast assumptions, (2) has not eliminated data, and (3) has furnished a reasonable explanation for the use of binary variables. Based on the

[34] EECo's filing contains documentation that explicitly identifies each of the binary variables used in the Brockton and Fall River industrial forecasting models (Exh. EUASC-1, Vol. 4, App. 5, at 31, 49). Binary variables are represented by one of two values, indicating either the presence or absence of a particular attribute.

foregoing, the Department finds that Eastern has complied with Directive Four regarding the Company's industrial energy forecast.

6. Other Energy Forecasts

Eastern prepared forecasts of streetlighting energy sales, system transmission losses, and internal energy use (Exh. EUASC-1, Vol. 2, at 71-72). Each of these forecasts are discussed infra.

a. Streetlighting

Eastern's streetlighting energy sales accounted for 0.6 percent of Eastern's total retail sales in 1991 (Exh. EUASC-1, Vol. 3, at C-8). Eastern's streetlighting sales declined from 23.5 Gwh in 1978 to 15.4 Gwh in 1991, a compound growth rate of -3.2 percent (id.). Eastern forecasted streetlighting sales to remain virtually flat at approximately 15.3 Gwh from 1992 through 2001 (id.). Eastern's forecasted streetlighting sales are presented in Table 2.

EECo stated that it forecasted streetlighting sales in the Brockton and Fall River service areas as a ratio of KWH per residential customer using regression analysis (id. at 71). Inputs to the service area streetlighting forecasts were time trends, binary variables, historical streetlighting per residential customer data, and Eastern's residential customer forecast (id.; Exh. EUASC-1, Vol. 4, App. 6, at 4, 6).

For purposes of this review, the Department finds that Eastern has established that its forecast of streetlighting sales is reviewable, appropriate, and reliable.

b. Transmission Losses

EECo stated that it projected transmission losses to represent about four percent of the Brockton service area's total energy requirements throughout the forecast period, and about three percent of the Fall River service area's total energy requirements throughout the forecast period (Exh. EUASC-1, Vol. 2, at 72).

EECo forecasted transmission losses by (1) calculating the average of losses between the years of 1989 through 1991 as a percentage of total energy sales plus internal energy use during those years, and (2) applying the resulting percentages to forecasts of total energy requirements (id.; Exh. EUASC-1, Vol. 4, App. 6, at 17).

For purposes of this review, the Department finds that Eastern has established that its forecast of transmission losses is reviewable, appropriate, and reliable.

c. Internal Energy Use

EECo indicated that internal energy requirements in the Brockton and Fall River service areas historically have represented less than one percent of the total energy requirements of the respective service areas (Exh. EUASC-1, Vol. 3, at C-10). Eastern expects that internal energy use will remain a very small fraction of total energy requirements throughout the forecast period (id.).

EECo stated that internal energy use in the Brockton and Fall River service areas was projected on the basis of regression analysis of recent time trends (id., Vol. 2, at 73). Inputs used in the models were historical Company energy use data, a time trend, and binary variables (id., Vol. 4, App. 6, at 12, 14).

The Department finds that Eastern has established that its forecast of internal energy use is reviewable, appropriate, and reliable.

d. Compliance with Directive Five Regarding the Company's Forecast of Internal Use Energy Requirements

In the past, the Siting Council noted concern about the Company's lack of documentation of the methodology used to forecast internal use energy requirements. 1988 EUA Decision, 18 DOMSC at 19, 20. EECo's filing in this case includes documentation of service area forecasts of internal energy use. Based on the foregoing, the Department finds that Eastern has complied with Directive Five.

7. Conclusions on the Energy Forecast

The Department has accepted Eastern's methodology for forecasting economic and demographic factors and electricity price. The Department has found that Eastern has established that its methodologies for forecasting energy requirements for the residential sector, the commercial sector, the industrial sector, streetlighting, transmission losses, and internal energy use are reviewable, appropriate, and reliable. Accordingly, the Department finds that Eastern has established that its methodology for forecasting energy requirements is reviewable, appropriate, and reliable.

D. Peak Load Forecast

1. Description

EECo stated that Eastern was a winter peaking system from 1978 through 1981, and, except for 1987, was a summer peaking system from 1982 through 1991 (Exh. EUASC-1, Vol. 3, at C-11). Eastern indicated that it expected to remain a summer peaking system throughout the forecast period (id. at C-11 through C-16). Eastern's summer peak grew from 365.5 MW in 1978 to 500.5 MW in 1991, a compound growth rate of 2.5 percent (id. at C-11). Eastern forecasted unadjusted summer peak demand to grow from 495.2 MW in 1992 to 621.4 MW in 2001, a compound growth rate of 2.6 percent (id.).[35] Eastern's forecasted peak loads are presented in Table 1.

EECo stated that it forecasted Eastern's coincident seasonal peak demand using load factor models (Exh. EUASC-1, Vol. 2, at 72).[36, 37] These models used regression analyses

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35 The unadjusted peak demand figures do not reflect the projected savings from Company-sponsored DSM programs (Exh. EUASC-1, Vol. 4, App. 7, at 4). If projected DSM savings are included, the forecasted summer peak load figures would be 490.8 MW in 1992 increasing to 575.9 MW in 2001, a compound growth rate of 1.8 percent (id., Vol. 3, at C-11).

36 EECo indicated that its sector-by sector energy requirements forecasts were primary inputs to the Company's peak load forecast (Exh. EUASC-1, Vol. 4, App. 7, at 1). See Section II.C., supra, for a complete discussion of EECo's energy requirements forecasts.

to predict winter and summer load factors on the basis of time trends, peak-producing temperatures, and degree days (id.). Eastern's coincident winter and summer peak loads were calculated by dividing average hourly energy consumption during a year by the model-predicted load factor for that year (id., Vol. 4, App. 7, at 11, 21).[38] EECo stated that separate load factor models were constructed for the summer and winter seasons, and for the Blackstone Valley, Newport, and Eastern Edison distribution companies (id.). EECo stated that it summed the coincident peaks of the three distribution companies, plus system losses to obtain the total, unadjusted EUA system peak demand forecast (id. at 4). Projected Company-sponsored DSM savings were subtracted from the unadjusted forecast to yield the final, "with DSM" load forecast (id.).

EECo stated that it used historical weather data from the years of 1978 through 1991 to estimate its load factor models (Tr. 1, at 91). The summer season models were estimated from historical degree day data[39] and temperature data from the months of June, July, August, and September (Exh. EUASC-1, Vol. 4, App. 7, at 1).[40] Winter models were estimated from historical degree day data and temperature data from the months of December

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37 EECo defined "load factor" as the ratio of average load during a specified period to the maximum load occurring during the same period (Exh. EUASC-1, Vol. 1, at 30).

38 EECo calculated average hourly energy consumption by dividing total annual energy consumption by 8760, the total number of hours in a year (Exh. EUASC-1, Vol. 4, App. 7, at 1).

39 EECo stated that the degree day explanatory variable used in the EECo summer load factor model was equal to two times the sum of the cooling degree days during the period of May through September, plus the sum of heating degree days during the winter power year months (Exh. EUASC-1, Vol. 4, App. 7, at 3-4). EECo indicated that this degree day concept exhibited greater statistical strength than a range of other concepts that it tested (id. at 4).

40 EECo stated that summer peak temperature was represented in the models as the weighted sum of (1) the maximum temperature two days before peak, (2) the maximum temperature on the day before peak, and (3) the maximum temperature on the day of peak (Exh. EUASC-1, Vol. 4, App. 7, at 3). EECo indicated that it assigned weights of 20 percent, 30 percent, and 50 percent, respectively, to the days identified (id.).

and January (id.). EECo indicated that it obtained historic weather data from the Providence weather station of NOAA, and historic energy and demand data from in-house sources (id. at 2, 4).[41]

Eastern stated that it developed high and low case bandwidths for its peak load forecast (Exh. EUASC-1, Vol. 2, at 74). EECo indicated that its bandwidths were calculated from bandwidths developed by NEPOOL (id.). EECo stated that its low and high case peak load bandwidths represent 90 percent and 10 percent confidence levels, respectively, with the low case having a 90 percent chance of being exceeded, and the high case having a 10 percent chance of being exceeded (id. at 73). EECo stated that NEPOOL developed its peak load bandwidths using load forecasting models similar to those used by Eastern (id. at 74). However, the Company did not provide documentation of (1) the methodology employed by NEPOOL to develop the bandwidths, or (2) the inputs used in the NEPOOL peak load models.

EECo stated that it considered but rejected the possibility of utilizing a peak load forecasting methodology that projects peak load on an hourly basis, disaggregates end-uses, and accounts for the effects of day type and load management (Exh. EFSC-D-36). EECo determined that the approach reflected in the current filing is appropriate for a company the size of Eastern because it requires significantly less resources to develop, implement, and maintain than a disaggregated end-use model (id.).[42] In addition, the Company asserted that its current methodology uses reasonable statistical projections to account for the effects of

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41 According to EECo, its load factor models exhibited reasonable statistical strength. The record in this case indicates that the EECo summer load factor model produced an R-squared of 0.69, and that the EECo winter load factor model produced an R-squared of 0.65 (Exh. EUASC-1, Vol. 4, App. 7, at 8, 16).

42 EECo estimated that the initial cost of developing and implementing a disaggregated peak load model, using load shapes supplied by NEPOOL, would be $153,400, plus an additional $86,400 per year for maintenance of data sets and documentation of the annual forecast (Exh. EFSC-RR-1, Supplemental Response, at 1, 3).

weather, load management, and any underlying trends that may effect load factor (Exh. EFSC-RR-1, Supplemental Response, at 4, 5).[43]

Dr. Ryan stated that the Company obtained information regarding specific end-use contributions to peak from a study of the technical potential for conservation and load management prepared for Eastern by XENERGY, Inc. ("XENERGY") in March, 1992, and that it is therefore unnecessary for the Company to develop and implement a peak load forecasting methodology that is disaggregated by end-use (Tr. 1, at 90). Dr. Ryan added that the technical potential study contains the information necessary for the Company to design effective load management programs, and that the effects of future load management programs are accounted for in the Company's energy forecasts (id. at 82, 90).

2. Analysis and Findings

Eastern has demonstrated that it has implemented a peak load forecasting methodology that accounts for some of the key determinants of peak load, including weather effects and the impacts of DSM programs. In addition, the record in this case indicates that the Company's conservation and load management technical potential study provides insights into the current energy and demand consumption characteristics of the end-uses in each class of service that contribute to peak demand.

In the past, the Siting Council has approved methodologies that are similar to Eastern's forecasting methodology in terms of their use of a load factor as a means of forecasting peak load. See Nantucket Electric Company, 21 DOMSC 208, 253 (1991) ("1991 Nantucket Decision"); 1990 MMWEC Decision, 20 DOMSC at 37-39. Unlike these methodologies, Eastern's methodology exhibits the notable strength of accounting for the effects of weather.

The Department acknowledges that the Company has made significant progress in disaggregating its energy requirements forecasts, and that these energy forecasts are key

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43 Dr. Ryan stated that, for its next forecast filing, the Company intends to enhance its peak load forecasting methodology by disaggregating EECo's seasonal peaks by class of service (Tr. 1, at 85).

inputs into the Company's peak load forecast. However, the Department notes that the disaggregation of the energy forecasts is not clearly reflected in the Company's peak load forecast because the disaggregated energy forecasts are essentially re-aggregated before they are applied to the model-predicted load factors. In addition, the Department notes that an inherent weakness of Eastern's peak load forecasting methodology is the incorporation of the implicit assumption that historical relationships between weather, load factor, and energy use will continue into the future.

Further, while we recognize that the results of the Company's DSM technical potential study provides some understanding of the effects and end-uses that contribute to the Company's peak load, these results are static and must be updated regularly to account for their dynamic nature. Therefore, in order for the Department to approve the peak load forecast in Eastern's next filing, the Company must furnish a plan for regularly updating the results of its DSM technical potential study that are particularly relevant to the Company's understanding of end-uses that contribute to the Company's peak load.

The Department notes that end-use peak load modeling is required if the effects of future changes in structural factors (e.g. energy efficiency improvements resulting from price, regulatory and legislative changes, changes in socioeconomic and demographic factors, and changes in the availability of a multitude of electricity-consuming products and equipment) are to be clearly reflected in the peak load forecast. An aggregate, econometric approach, such as that employed by Eastern, is not as well-suited for analyzing and responding to structural changes.

Finally, the Department is concerned that the bandwidths developed for the Company's peak load forecast are extremely broad, and that they therefore provide only limited information regarding a plausible range of outcomes. Further, the lack of documentation regarding the development of the peak load forecast bandwidths makes it difficult for the Department to assess the extent to which the peak load forecast demonstrates sensitivity to changes in critical planning assumptions. Therefore, in order for the Department approve the peak load forecast in Eastern's next filing, the Company must furnish complete documentation of the methodology employed to develop peak load forecast bandwidths.

Despite the continued lack of disaggregation by end-use and the lack of documentation of Company's development of forecast bandwidths, Eastern has significantly enhanced its load factor models since the previous Siting Council review. Further, the record in this case indicates that the Company's load factor models exhibit reasonable statistical strength. Accordingly, for the purposes of this review, the Department finds that Eastern has established that its peak load forecast is reviewable, minimally appropriate and minimally reliable.

3. Compliance with Directives Six and Eight Regarding the Company's Peak Load Forecast

In the previous review of Eastern's peak load forecast, the Siting Council noted the lack of disaggregation in the forecast, and the methodology's inability to account for many of the determinants of peak load. 1988 EUA Decision, 18 DOMSC at 96. Subsequently, the Company has developed an enhanced peak load forecasting methodology that explicitly incorporates weather effects. In addition, the Company has indicated that it anticipates future filings to reflect a peak load forecasting methodology that is disaggregated by class of service. Based on the foregoing, the Department finds that Eastern has complied with Directive Six regarding the Company's peak load forecast.

Previously, the Siting Council noted that Eastern provided no indication of how changes in planning assumptions and parameters would result in changes in the demand forecast. 1988 EUA Decision, 18 DOMSC at 99. The Department recognizes that in this case, Eastern has (1) developed uncertainty bandwidths around its peak load forecast, and (2) developed peak load forecasts that reflect the effects of future Company-sponsored DSM programs. However, as noted in this section, the Company failed to provide adequate documentation regarding the development of peak load forecast bandwidths. In addition, the Company has not provided tests of sensitivity of the energy and peak load forecasts to other major planning assumptions and parameters, such as scenarios of high or low economic growth. Accordingly, the Department finds that Eastern has not complied with Directive Eight regarding the Company's peak load forecast.

E. Conclusions on the Demand Forecast

The Department has found that Eastern has complied with Directives One through Seven of the 1988 EUA Decision, and has not complied with Directive Eight of that same decision.

The Department has also found that Eastern has established that its methodology for forecasting energy requirements is reviewable, appropriate, and reliable. In addition, the Department has found that Eastern's methodology for forecasting peak load is reviewable, minimally appropriate, and minimally reliable.

Accordingly, the Department hereby APPROVES Eastern's 1992 demand forecast.

III. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

The Reorganization Act provides that every electric company shall, individually or jointly with others, file with the Department a long-range forecast with respect to the electric power needs and requirements of its market area, taking into account wholesale bulk power sales or purchases or other cooperative arrangements with other electric companies, for the forecast period (§ 12). Pursuant to the Reorganization Act, the Siting Council's function of review of an electric company's long-range plans will be performed by the Department (id.). Further, in accordance with the Reorganization Act, all orders, rules and regulations duly made, and all legal and decisional precedents established by the Siting Council that were pending immediately prior to the effective date of the Reorganization Act, shall continue in force and the provisions thereof shall thereafter be enforced, until superseded, revised, rescinded or cancelled in accordance with law by the Department (§ 46).

The Siting Council regulations, as adopted by the Department, set out the specific filing requirements for electric company supply plans. The regulations provide that such filings are required to include a description of the company's plans to meet forecasted needs or requirements. See 980 C.M.R. 7.04. In addition, the Department will review the supply plans submitted by an electric company to determine whether the supply plans fulfill the energy, environmental and economic policies of the Commonwealth. 980 C.M.R. 7.04(1)(b).

In determining that the supply plan will meet the forecasted needs or requirements of an electric company, the Department will review the plan for both adequacy and cost. 1992 Fitchburg Decision, 24 DOMSC at 351, 1988 EUA Decision, 18 DOMSC at 100. The Siting Council has defined adequacy for an electric company as the ability to provide sufficient capacity to meet its peak loads and reserve requirements throughout the forecast period. Id. Further, the Siting Council has determined that different standards of review are appropriate for evaluating supply adequacy in the short- and long-run. Id.; Commonwealth Electric Company and Cambridge Electric Light Company, 15 DOMSC 125, 134 (1986) ("1986 CECo/CELCo Decision").

In order to establish adequacy in the short-run, an electric company must demonstrate that it has an identified, secure, and reliable set of energy and power supplies sufficient to meet its capability responsibility ("CR") under a reasonable range of contingencies, or that it operates pursuant to a specific action plan guiding it in being able to rely upon alternative supplies in the event of certain contingencies. 1992 Fitchburg Decision, 24 DOMSC at 351, 1988 EUA Decision, 18 DOMSC at 101-102. In order to establish adequacy in the long-run, an electric company must demonstrate that its supply planning process can identify and evaluate a reasonable range of resources options on a continuing basis while allowing sufficient time for the company to make appropriate supply decisions to ensure adequate cost-effective energy and power resources over the forecast period. 1992 Fitchburg Decision, 24 DOMSC at 352, 1988 EUA Decision, 18 DOMSC at 102.

Finally, an electric company must demonstrate that a supply plan minimizes the cost of power. 1992 Fitchburg Decision, 24 DOMSC at 352, 1988 EUA Decision, 18 DOMSC at 100. In order to determine whether an electric company's supply plan minimizes the cost of power, the Siting Council has reviewed an electric company's supply planning methodology and processes of identifying and evaluating a variety of supply options. 1992 Fitchburg Decision, 24 DOMSC at 352, 1988 EUA Decision, 18 DOMSC at 100-103. An electric company must demonstrate that it has identified a reasonable range of resource options by (1) compiling a comprehensive array of available resource options, and (2) developing and applying appropriate criteria for screening its array of available resource options. 1992 Fitchburg Decision, 24 DOMSC at 353, 1988 EUA Decision, 18 DOMSC at 103. In reviewing an electric company's resource evaluation process, the company must demonstrate that it fully evaluates all resource options. Id.

B. Description of the Supply Planning Process

In this section, the Department (1) describes Montaup's planning goals and objectives, (2) presents an overview of Montaup's planning process, and (3) describes the first step of Montaup's planning process: determination of resource need. The Department's review of the remaining steps of Montaup's resource planning process – identification and screening of alternative supply- and demand-side resources available to meet future resource need, the creation of potentially viable resource plans to meet requirements, analysis of the interactions among candidate and existing resources, and choosing a course of action– is set forth in Sections III.D., infra.

Montaup stated that it has developed a new resource planning process that is intended to produce an economical and balanced mix of supply side and demand side resources to meet the energy and capacity needs of Montaup (Exh. EUASC-1, Vol. 2, at 1). Montaup indicated that the resource planning process is intended to meet all of the following criteria: (1) maintain resources adequate to meet projected energy and demand requirements plus NEPOOL reserves; (2) promote electrical energy efficiency by encouraging all cost-effective efficiency improvements in end-uses and system operations; (3) provide flexibility and diversity in the resource portfolio to minimize cost and operational risk in meeting energy and capacity requirements; and (4) provide energy consistent with efficient, safe and "environmentally compatible" operation at the lowest practical cost to customers (id.).

Montaup stated that its resource planning process is in large measure consistent with the Massachusetts IRM regulations (id.). See 220 C.M.R. 10.00 et seq. Montaup stated that its planning process entails: (1) determination of capacity and energy requirements based upon review of Montaup's energy and load forecasts and resource inventory; (2) identification and screening of resource options available to meet identified needs; (3) creation of potentially viable option sets from highly-ranked individual resources; (4) analysis of the interactions among candidate resource options and existing resources; and (5) choosing the course of action that best balances a range of system performance attributes (Exh. EUASC-1, Vol. 2, at 1).

The first step of Montaup's resource planning process entails making a determination of resource need (id.). Montaup indicated that the amount and timing of capacity need is determined by the difference between NEPOOL-calculated CR,[44] and the amount of capacity expected to be available from existing and committed resources (id. at 13). Thus, Montaup's determination of need involved both preparation of energy and demand forecasts, and a review of the inventory of existing and planned resources (Tr. 2, at 6). In addition, Montaup stated that an analysis of the uncertainties associated with peak load growth, fuel prices and the performance of the component parts of Montaup's resource inventory also is required in making a determination of future capacity need (Exh. EUASC-1, Vol. 2, at 13). A detailed discussion of Montaup's energy and demand forecasts is set forth in Section II., supra. A detailed discussion of Montaup's treatment of uncertainties in the resource plan is set forth in Section III.D.2.a.ii., infra.

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[44] Montaup stated that CR is the minimum amount of capacity a NEPOOL participant is required to purchase or own to meet its share of total NEPOOL required capacity (Exh. EUASC-1, Vol. 2, at 5). NEPOOL's calculation of a participant's CR is based on historic peak and average loads, and actual availabilities of the participant's units (id.).

C. Adequacy of the Supply Plan

1. Adequacy of the Supply Plan in the Short Run

a. Definition of the Short Run

In the past, the short run has been defined for all electric companies as four years from the date of final hearing or from the date of the response to the final record request, whichever is later. 1992 BECO Decision, 24 DOMSC at 170-171; 1991 Nantucket Decision, 21 DOMSC at 268. The final hearing in this proceeding was held on July 29, 1992 and the final record request response was dated August, 1992. Consistent with previous decisions, the short run in this proceeding extends from the summer of 1993 through the summer of 1996.[45]

b. Base Case Supply Plan

The data shown in Table 3 compare Montaup's base case resource capability to its capability responsibility over the years 1993-1996. These data indicate that Montaup is projecting capability surpluses ranging from 182.1 MW in 1993 to 197.6 MW in 1996, or 16.8 percent and 18.3 percent, respectively.

Accordingly, the Department finds that Montaup has established that its base case supply plan is adequate to meet requirements in the short run.

c. Short-Run Contingency Analysis

In order to establish adequacy in the short run, a company also must establish that it can meet its forecasted needs under a reasonable range of contingencies. In the past, the Siting Council has analyzed electric companies' adequacy in the short run in terms of single contingency and double contingency cases, generally involving high load growth and cancellation or delays in planned resources. 1992 Fitchburg Decision, 24 DOMSC at 360; 1992 BECO Decision, 24 DOMSC at 307. Here, Montaup has utilized a methodology for

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45 The Department notes that since the summer of 1992 has passed it will not be included in the short run analysis of adequacy.

analyzing short-run adequacy in terms of the uncertainties associated with four key factors, as follows: (1) peak load growth; (2) DSM penetration; (3) the continued operation of existing resources; and (4) the successful completion and operation of new supply-side resources (Exh. EUASC-1, Vol. 2, at 13). For each year of the short-run period, Montaup developed a distribution of capacity requirements based on bandwidths and probabilities assigned to the four key uncertainty factors (Exh. EFSC-RR-3). Thus, Montaup asserted that its methodology reflected the effects of uncertainty based on many possible combinations of key uncertainty factors, as opposed to selected pairings of contingency factors (Exh. EUASC-1, Vol. 2 at 3).[46]

Montaup stated that it used a probabilistic technique to quantify the effects of uncertainty on short-run adequacy (Exh. EFSC-RR-3). Essentially, Montaup's technique yielded annual reductions in resources derived from the probability-weighted effects of the four uncertainty factors (id.).[47] The reductions were applied to Montaup's capacity projections, yielding a stream of "Adjusted Capacity" levels (Exh. EUASC-1, Vol. 2, at 36). See Table 4. That stream of capacity levels -- reduced through Montaup's uncertainty methodology -- still indicated surpluses for each year of the short run period (id.). In addition, Montaup calculated the confidence level of achieving at least that level of surplus shown in its Adjusted Capacity levels, as follows: 1993, 69 percent; 1994, 71 percent; 1995, 78 percent; 1996, 54 percent (Exh. EFSC-R-21).[48]

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46 Montaup stated that its distributions of capacity requirements consisted of up to 180 separate values for each year of the short-run period (Exh. EFSC-RR-3).

47 Montaup's reduction in resources was based on the expected values (i.e., probabilistic average value) attributable to each individual uncertainty component (Exh. EFSC-RR-3). Essentially, Montaup calculated expected values using high and low bandwidth levels, took the probabilistic average, and then summed the expected values to establish an overall reduction in resources for each year of the short run (id.).

48 Montaup defined its confidence levels as representing the likelihood of maintaining a capacity surplus at least the size of that resulting from its Adjusted Capacity position (Exh. EFSC-R-21).

Finally, Montaup described an action plan capable of providing about 19.2 MW of resources in the event of a short-run contingency (Tr. 2, at 16, 30). The Company's witness, Mr. Kirby, stated that 14 MW to 15 MW could be obtained readily from the Somerset generating unit, and that 4.2 MW could be obtained by reinstituting the CHOICE interruptible load program (id.).[49]

In the past, the Siting Council has accepted short-run contingency analyses that included an electric company's adequacy in terms of single and double contingency cases. 1992 Fitchburg Decision, 24 DOMSC at 33-36; 1991 Nantucket Decision, 21 DOMSC at 208, 275-276. Here, Montaup has presented a multiple contingency analysis, combining the effects of four key variables on an aggregated, probabilistic basis. The Department recognizes that the variables selected by Montaup in its uncertainty analysis are critical to a comprehensive assessment of uncertainty. In addition, Montaup's methodology evaluated a wide range of possible combinations of those variables over the short-run period. However, the Department notes that Montaup's analysis included combinations that do not represent contingencies to adequacy. For example, Montaup included combinations such as low load growth, high DSM penetration, and high success for new supply-side additions. While combinations such as those may indicate the likelihood of excess capacity – an important component of long-term forecasting – such combinations are less critical from the perspective of short-run adequacy. To the extent that Montaup's results were weighted by those combinations, the analysis is less useful for assessing the effects of uncertainty on adequacy. Despite this shortcoming, Montaup's methodology for analyzing short-run contingencies exhibits overall strengths. Accordingly, for purposes of this review, the Department accepts Montaup's methodology as a means of analyzing short-run contingencies.

The Department notes that Montaup has demonstrated adequacy in each year of the short run period while reflecting resource reductions due to the effects of multiple

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49 Mr. Kirby stated that if the Somerset unit were to operate at its maximum output level, it could produce 14 MW of additional output (Tr. 2, at 28). Mr. Kirby noted that the higher output could be called upon in a tight capacity situation, despite the fact that this would add "additional stress" to the unit (id.).

uncertainties. In addition, Montaup has presented an action plan that can provide at least 19.2 MW of resources in the short run.[50]

Accordingly, the Department finds that Montaup has established that it has adequate resources to meet its projected requirements under a reasonable range of circumstances in the short run.

2. Adequacy of the Supply Plan in the Long Run

Montaup's long run planning period is the remaining forecast horizon beyond the short run; this period extends from Summer, 1996 to Winter, 2001. A review of Montaup's resource inventory indicates that Montaup's summer, 1992 net generating capability (owned and purchased capacity minus sales) was 1,203 MW (Exh. EUASC-1, Vol. 2, at 7). As indicated in Section III.A., supra, the Department requires an electric company to establish adequacy in the long run by demonstrating that its planning process can identify and fully evaluate a reasonable range of resource options on a continuing basis while allowing sufficient time for the company to make appropriate supply decisions to ensure adequate cost-effective energy and power resources over the forecast period. As discussed in Section III.D., infra, the Department has found that Montaup has established that it identified a reasonable range of resource options. The Department has made no finding on whether Montaup has evaluated a reasonable range of resource options. Accordingly, the Department makes no finding on whether Montaup has established that its supply planning process ensures adequate resources to meet requirements in the long run.

3. Conclusions on Adequacy of the Supply Plan

The Department has found that Montaup has established that its base case supply plan is adequate to meet its requirements in the short run. The Department has made no finding on whether Montaup has established that it has adequate resources to meet its projected

50 The Department notes that Montaup's action plan may not require implementation since Montaup has demonstrated surpluses in each year of the short-run period.

requirements in the long run. However, the Department notes that Montaup's base case supply plan would satisfy its capability responsibility throughout the long run planning period (Exh. EUASC-1, Vol. 2, at 36). Accordingly, the Department makes no finding on whether Montaup has established that its supply planning process ensures adequate resources to meet requirements in the long run.

D. Least Cost Supply

In this section, the Department reviews Montaup's processes for identifying and evaluating resource options.

1. Identification of Resource Options

Montaup stated that it identified, screened and grouped generation technologies and DSM programs for evaluation (Tr. 2, at 80-83). The Department focuses its review on whether Montaup identified a reasonable range of resource options by (1) compiling a comprehensive array of available resource options, and (2) developing and applying appropriate criteria for screening its array of resource options.

a. Available Resource Options

In order to determine whether Montaup compiled a comprehensive array of available resource options, the Department must determine whether Montaup compiled adequate sets of available resource options for each type of resource identified during the current proceeding.

i. Types of Resource Sets

Montaup identified two types of resource sets for consideration in its supply planning process: (1) generic, Montaup-sponsored generating and DSM resources compiled as part of Montaup's "generic expansion plan"; and (2) specific supply- and demand-side resources offered to Montaup from developers of qualifying facilities ("QF"), independent power producers ("IPPs"), other utilities or their affiliates, and providers of DSM technologies and programs (id. at 87-88).

The Department finds that Montaup has identified a reasonable range of resource sets.

ii. Compilation of Resource Sets

Montaup indicated that it first developed an expansion plan by identifying and screening generic supply-side resources and demand-side resources as described below. Montaup referred to this expansion plan as its "generic expansion plan" (id. at 85).

Montaup stated that, in its generic expansion plan, it identified the full range of supply-side technologies that were currently viable or anticipated to be viable in the near term (id. at 81; Exh. EUASC-1, Vol. 2, at 20). Montaup identified generic supply technologies through reviews of (1) literature from the Electric Power Research Institute ("EPRI"), NEPOOL, and the Office of Technology Assessment of the United States Congress, and (2) vendor contracts (Exh. EUASC-1, Vol. 2, at 20). Montaup stated that it last performed a systematic technology review in January, 1989, but that it regularly updates its study results as new information becomes available (id.). Montaup indicated that this phase of the supply resource identification process was limited to a set of generic resource technologies (id.). Montaup stated that the technologies identified and evaluated in its generic process included coal gasification combined cycle, photovoltaic cells, compressed air storage, and "traditional" oil, coal and gas-fired technologies (id.; Tr. 2, at 81).

In the past, the Siting Council has found that an adequate set of company-owned generation resources included a wide range of capacity factors, size increments, fuel types and technologies. Braintree Electric Light Department, 24 DOMSC 1, 50 (1992) ("1992 BELD Decision"); 1991 Nantucket Decision, 21 DOMSC at 268; 1990 MMWEC Decision, 20 DOMSC at 64; Boston Edison Company, 18 DOMSC 201, 257, 258 (1989) ("1989 BECo Decision"). The Department notes that Montaup's compilation of supply resources encompasses a wide range of fuel types and technologies. In addition, the Department recognizes that the set of generating technologies identified by Montaup is capable of operating at a wide range of capacity factors and size increments. Accordingly, the Department finds that Montaup has compiled an adequate resource set of new Company-owned supply sources.

Montaup stated that it identified Company-sponsored DSM resources by (1) assessing the full technical potential for energy and peak load savings available from all retail customers within the EUA service territories, and (2) reviewing DSM-related information from various sources (Exh. EUASC-1, Vol. 2, at 22).

Montaup indicated that it contracted with XENERGY, an energy consulting firm, to conduct a study assessing the technical potential for peak and energy savings within the EUA service territories (id.). Montaup stated that the technical potential study data assessed the "energy and demand reductions that could be realized if the existing stock of electricity consuming devices were replaced with the most efficient alternatives currently available, regardless of cost or cost-effectiveness" (id.). Specifically, Montaup stated that XENERGY analyzed (1) the application of 42 DSM measures for five residential end-uses, (2) the application of 32 commercial sector DSM measures for ten building types and seven end-uses, and (3) the potential for savings by two-digit SIC code in the industrial sector (id.).[51]

Montaup stated that, as part of its DSM resource identification process, it keeps apprised of demand-side technological developments through information from manufacturers, technical journals, other utilities, and various parties interested in Montaup's energy conservation activities (Exh. EUASC-1, Vol. 2, at 22).

Through the results of the XENERGY DSM technical potential study, Montaup has identified significant energy and capacity savings that may be realized through the implementation of DSM measures in its service areas. In the past, the Siting Council has found that the results of a comprehensive DSM technical potential study conducted by a reputable energy consulting firm constituted the compilation of an adequate array of DSM resources. 1991 Nantucket Decision, 21 DOMSC at 268. Accordingly, the Department finds that Montaup has compiled an adequate set of Company-sponsored DSM resources.

Montaup indicated that as the anticipated date of need approaches, its resource identification process would be expanded, through the issuance of requests for proposals ("RFPs"), to encompass the entire universe of available resources (Exh. EUASC-1, Vol. 2,

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[51] Results of XENERGY's analysis is indicated that DSM technical potential for the Montaup system was 251 MW of winter peak load, 177 MW of summer peak load, and 1,101,788 megawatthours ("MWH") of annual energy (Exh. EUASC-1, Vol. 4, at IV-137).

at 23, 24). Montaup stated that solicitations for supply-side and demand-side resources would be run in parallel, and resources selected through the respective screening processes would be evaluated together in an integrated production cost analysis (id. at 23). Montaup stated that it anticipated a competition among QFs, IPPs, utility companies and their affiliates, and "energy conservation efforts" to meet the Montaup system's future resource needs (id. at 88). Montaup added that its generic expansion plan would serve as the "unit" against which responses to RFPs would compete (id. at 87).[52]

Montaup has developed a methodology that will allow it to compile an adequate resource set for purchases of specific resources from QFs, IPPs, other utilities or their affiliates, and providers of DSM technologies and programs once Montaup's proposed RFPs are issued. In the past, the Siting Council has found that a formal RFP process subject to approval by the Department constitutes an appropriate methodology for compiling a set of available non-utility purchases. 1991 Nantucket Decision, 21 DOMSC at 280; 1989 BECo Decision, 18 DOMSC at 258; 1988 EUA Decision, 18 DOMSC at 115. Accordingly, the Department finds that Montaup has developed a methodology for compiling an adequate resource set for specific purchases from QFs, IPPs, other utilities or their affiliates, and providers of DSM technologies and programs.

iii. Conclusions on Available Resource Options

The Department has found that Montaup has identified a reasonable range of resource options. The Department has also found that Montaup has compiled an adequate set of generic, Montaup-sponsored generating and DSM resources. In addition, the Department has

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52 Montaup plans to issue supply- and demand-side RFPs as part of its resource identification and screening process "when a need for additional long-term resources is identified" (Exh. EUASC-1, Vol. 2, at 23, 24). Since Montaup's current load and capability forecast indicates no new capacity need until the year 2000, Montaup has stated that it plans to begin the solicitation process in 1994 (id. at 24). Within this timeframe, Montaup would have six years to complete resource solicitation, proposal evaluations, contract negotiations, and up to four years of construction lead time (id. at 2).

found that Montaup has developed a methodology for compiling an adequate resource set for specific purchases from QFs, IPPs, other utilities or their affiliates, and providers of DSM technologies and programs. Accordingly, the Department finds that Montaup has demonstrated that it compiled a comprehensive array of resource options.

b. Development and Application of Screening Criteria

To determine whether Montaup developed and applied appropriate criteria for screening its array of available resource options, the Department reviews the criteria developed and applied to: (1) generic, Montaup-sponsored generating and DSM resources; and (2) specific supply- and demand-side resources offered to Montaup from developers of QFs, IPPs, other utilities or their affiliates, and providers of DSM technologies and programs.

i. Company-sponsored Generating Resources

Montaup stated that supply resources identified in the development of the generic expansion plan were screened based upon projected busbar costs and a range of non-price factors (Exh. EUASC-1, Vol. 2, at 21). Mr. Kirby stated that busbar costs were essentially the costs to produce energy from a particular facility, including capital, operation and maintenance, and fuel costs (Tr. 2, at 108). Montaup stated that busbar costs of specific technology types were calculated for capacity factors consistent with each technology's operation as a baseload, intermediate or peaking generating unit (Exh. EUASC-1, Vol. 2, at 21). Montaup then ranked the technologies according to duty type (id.).[53] Montaup indicated that its non-price scoring was based on the following factors and weights: technology development status, plant size, ability to be licensed, and fuel source were each assigned a 20 percent weighting factor; environmental impacts were assigned a weighting factor of ten percent; and construction lead time and siting flexibility each were assigned a

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[53] "Duty type" refers to a generating facility's operation as either a baseload, intermediate, or peaking facility.

weighting factor of five percent (id.). Montaup did not provide evidence or documentation of the methods used to apply the aforementioned non-price weighting factors to each of the identified generating technologies.

Montaup stated that it drew generating technology cost and design parameters from documents published by NEPOOL, EPRI, and the U.S. Congress' Office of Technology Assessment (id. at 20). Montaup indicated that screening and selecting technologies was based on a balancing of price (i.e., busbar cost) and non-price rankings, as opposed to selection based on a total score. (id. at 21). Montaup provided no evidence or documentation of methods used to balance price and non-price rankings in its screening process.

Montaup stated that screening of generating technologies identified in the generic expansion plan yielded four options that performed well in both price and non-price rankings (id.). The selected options were (1) an 80 MW combustion turbine peaking facility, (2) a 20 MW peaking/load management battery, (3) a 100 MW intermediate combined cycle unit, and (4) a 100 MW baseload fluidized bed coal plant (id.).

The Department notes that Montaup developed a set of criteria for screening generic, Company-sponsored generating resources that address both the price and the non-price aspects of these resources. The Department further notes that Montaup presented evidence of how costs were determined for the range of available generating technologies and duty types. In addition, the Department notes that Montaup has documented its non-price screening criteria and has presented the weights applied to each of these factors. However, Montaup did not provide evidence of the methods used to apply the weighting factors to each of the identified generating technologies. Similarly, Montaup provided no evidence of methods used to integrate price and non-price rankings in its screening process.

The Department is concerned that, without complete documentation regarding all aspects of the application of screening criteria to identified resources, a thorough review of the Company's screening process is difficult. Nonetheless, the Department finds, for the purposes of this review, that Montaup has established that it has developed and applied appropriate criteria for screening Company-sponsored generating resources.

ii. <u>Company-sponsored DSM Resources</u>

Montaup indicated that, for the purposes of its generic expansion plan, it screened DSM measures by applying a "total resource cost test" (Exh. EUASC-1, Vol. 2, at 21), whereby a DSM option is deemed cost-effective if the present value of the savings resulting from the option exceeds the present value of the costs associated with the option (<u>id.</u> at 23). Montaup indicated that it applied its screening process to all DSM measures identified in the XENERGY technical potential study, in addition to a series of generic load management measures (<u>id.</u> at 22, 23).

Montaup indicated that savings measured in the total resource cost test included the value of avoided fuel, capital, operation, maintenance, and environmental costs associated with energy and peak load reductions over the life of the measure (<u>id.</u> at 22). Montaup did not provide documentation of the actual values attached to each of the costs noted above. Montaup added that costs in the total resource cost test included all measure or program costs incurred by the utility or the participant (<u>id.</u> at 22-23). Utility costs included the development, start-up, marketing, implementation, monitoring, and evaluation of DSM options; participant costs included the purchase and installation of measures by participants after any utility incentives, and incremental increases or decreases in operation and maintenance costs resulting from the DSM option (<u>id.</u> at 23). Montaup stated that it obtained information regarding costs and other aspects of demand-side technologies from manufacturers, technical journals, other utilities, and various parties interested in Montaup's energy conservation activities (<u>id.</u> at 22).

Montaup stated that application of the DSM screening process resulted in the selection of the measures packaged in the 14 programs that comprise Montaup's committed DSM resource inventory (<u>id.</u>). Montaup indicated that these programs were designed to produce energy and peak load savings from each of the customer classes served by Montaup's retail affiliates (<u>id.</u> at 9).

Montaup stated that the demand-side programs screened in the manner described in Section III.D.1.b.ii., <u>supra</u>, are currently active, and also were included in Montaup's expansion plan to gauge the interaction of the supply and demand options in the resource evaluation and selection process (id. at 23). Montaup indicated that additional, generic DSM strategies were modeled to gain insights into the capabilities of UPLAN, Montaup's production costing software (id.).

The department notes that Montaup used the total resource cost test as the central criterion for screening DSM resources identified in (1) the XENERGY technical potential study discussed in Section III.D.1.a.ii., supra, and (2) a series of generic load management measures. The Department further notes that Montaup's DSM screening process exhibits notable strengths, particularly the inclusion by Montaup of avoided environmental costs in the DSM screening process. However, The Department also notes that Montaup provided limited information regarding application of the total resource cost test to determine the cost-effectiveness of potential DSM measures. The Department is concerned about the lack of clear documentation of specific values attached to the various components of Montaup's total resource cost test.

Overall, Montaup's process for screening Company-sponsored DSM programs is sound. Accordingly, the Department finds that, for the purposes of this review, Montaup has established that it has developed and applied appropriate criteria for screening Company-sponsored DSM resources.

iii. Purchased Resources

Montaup indicated that the screening process used in the evaluation of responses to future RFPs was analogous to screening systems applied to Company-sponsored generating and DSM resources in the generic expansion plan (id. at 21). Montaup indicated that supply resources would be selected based on a balanced score across the range of evaluative factors, as opposed to merely the lowest total price or non-price score (id. at 24). However, Montaup noted that scoring systems used for future RFPs may be modified to reflect increased emphasis on environmental impacts and project viability, and to evaluate all resource types more adequately (id.).

Montaup indicated that it plans to issue supply- and demand-side RFPs as part of its resource identification and screening process only "when a need for additional resource capacity is identified" (id. at 2). Since Montaup's current load and capability forecast indicates no new capacity need until the year 2000, Montaup stated that it plans to begin the solicitation process into 1994 (id.). To date, Montaup has not issued an RFP that has generated responses to be subjected to the screening process described supra. In addition, Montaup stated that the scoring systems applied to such an RFP may in fact be different from those used in the generic expansion plan. Accordingly, the Department makes no finding on whether Montaup has established that it has developed and applied appropriate criteria for screening purchased resources.

iv. Conclusion

The Department has found that, for the purposes of this review, Montaup has established that it developed and applied appropriate criteria for screening Company-sponsored generating resources. In addition, the Department has found that, for the purposes of this review, Montaup has established that it has developed and applied appropriate criteria for screening Company-sponsored DSM resources. Finally, the Department has made no finding on whether Montaup has established that it has developed and applied appropriate criteria for screening purchased resources. Accordingly, on balance, the Department finds that Montaup has established that it has developed and applied appropriate criteria for screening its array of available resource options.

c. Conclusions on Identification of Resource Options

The Department has found that Montaup (1) demonstrated that it compiled a comprehensive array of available resource options, and (2) developed and applied appropriate criteria for screening its array of available resource options.

Accordingly, the Department finds that Montaup has established that it has identified a reasonable range of resource options.

2. <u>Evaluation of Resource Options</u>

Montaup identified its resource planning goal as developing an economical and balanced mix of supply- and demand-side resources to meet the energy and capacity needs of its system (Exh. EUASC-1, vol. 2, at 1). Montaup indicated that the resource planning process is intended to meet all of the following criteria: (1) maintain resources adequate to meet projected energy and demand requirements plus NEPOOL reserves; (2) promote electrical energy efficiency by encouraging all cost-effective efficiency improvements in end-uses and system operations; (3) provide flexibility and diversity in the resource portfolio to minimize cost and operational risk in meeting energy and capacity requirements; and (4) provide energy consistent with efficient, safe and "environmentally compatible" operation at the lowest practical cost to customers (<u>id</u>.). Mr. Kirby stated that Montaup's resource evaluation process evaluated all resources on an equal footing, and that Montaup applied its resource evaluation process to all identified resources (Tr. 2, at 104-105).

Here, the Department reviews Montaup's resource evaluation process to determine whether Montaup (1) has developed a resource evaluation process that fully evaluates all resource options and treats all resource options on an equal footing, and (2) has applied its resource evaluation process to all of the resource options identified in Section III.D.1., <u>supra</u>.

In the past, a company's resource evaluation process has been reviewed in terms of its ability to reflect an adequate consideration of cost, risk minimization and diversity objectives. <u>1992 BELD Decision</u>, 24 DOMSC at 56; <u>1991 Nantucket Decision</u>, 21 DOMSC at 304; <u>1990 MMWEC Decision</u>, 20 DOMSC at 83; <u>Massachusetts Electric Company</u>, 18 DOMSC at 362-363 (1989) ("1989 MECo Decision"). Thus, in this section, the Department considers the extent to which Montaup incorporates cost, diversity, risk minimization, and environmental impacts in its supply planning process.

a. Evaluation Process

To meet Montaup's planning goal and criteria, Montaup developed a resource evaluation process that entailed: (1) creating potentially viable plans from identified resources; (2) conducting an analysis of planning uncertainties; (3) evaluating system attributes of potential plans using a database expansion model; and (4) evaluating the interactive aspects of potential plans and the existing Montaup system using a production cost model (Exh. EUASC-1, Vol. 2, at 28-30). Based on the results of its evaluation process, Montaup selected an expansion plan (id. at 30).

i. Creation of Potentially Viable Resource Plans

Montaup stated that its resource planning process entailed the creation of "potentially viable plans" from resources identified and screened in the manner described above (id. at 28). Montaup indicated that it considered a potentially viable plan to be a combination of screened resource options that was capable of fulfilling stated capacity needs (id.).

Montaup indicated that it devised 385 potentially viable plans for evaluation in the development of its generic resource plan (id.). Montaup stated that each of these plans consisted of a different combination of unit types, sizes and in-service dates, as well as different levels of demand-side management resources (id.). Montaup indicated that the plans did not represent all possible combinations, but instead identified a diverse range of likely combinations (id.; Tr. 2, at 66). Montaup did not provide documentation regarding the specific content of the potentially viable plans that were developed.

Mr. Kirby stated that Montaup developed plans to fill 300 MW of capacity need irrespective of the level of future capacity that actually may materialize during the ten year planning horizon (Tr. 2, at 66, 74). Mr. Kirby also indicated that planning for growth beyond the ten year horizon allowed Montaup to analyze the interactions between the ensuing set of resources added to the Montaup system and resources added beyond the planning horizon (id. at 74).

ii. Uncertainty Analysis

Montaup indicated that its resource evaluation process reflected the effects of uncertainty through the enumeration of a range of potential "futures" (Exh. EUASC-1, Vol. 2, at 29). Montaup referred to a "future" as a particular combination of planning uncertainties that affect "...the balance of supply and demand or the costs of maintaining the balance, and which (are) beyond the control of the EUA System" (id. at 25; Tr. 2, at 62).

Montaup stated that its uncertainty analysis consisted of formulating bandwidths for five different planning uncertainties resulting in 162 distinct futures. These uncertainties were: (1) low, base, and high cases for load growth; (2) low, base, and high cases for fuel prices; (3) low and high cases for DSM penetration; (4) low, base and high cases for supply-side capital costs; and (5) low, base and high cases for DSM costs (Exh. EUASC-1, Vol. 2, at 25-26; Tr. 2, at 64-65).

Montaup stated that it calculated high and low load growth bandwidths from information furnished by NEPOOL that reflected a regional projection of potential future loads (Exh. EUASC-1, Vol. 2, at 25). Montaup's development of a base case peak load forecast is discussed in Section II.D., supra.

Montaup indicated that its base case fossil fuel price forecast is based on actual and budgeted fuel prices escalated at rates forecast by DRI (id.). High bandwidth fuel prices were developed by increasing near-term fuel prices by 50 percent, followed by escalation at the DRI fossil fuel forecast rates (id. at 26). Montaup stated that the low case fuel price forecast was modeled by moderately decreasing fuel prices in the near term, followed by escalation at DRI coal price forecast rates (id.).

Montaup indicated that it obtained supply-side capital cost estimates from NEPOOL, added 25 percent to these costs to produce a high case bandwidth, and subtracted 25 percent from the NEPOOL costs to produce a low case bandwidth (id.). Montaup did not provide justification of the assumptions used to develop supply-side capital cost bandwidths.

Montaup developed base case projections of DSM costs in the manner described in Section III.D.2.b.i., supra. Montaup stated that it produced a low case bandwidth for DSM costs by halving the base case, and that it produced a high case bandwidth for DSM costs by doubling the base case (id.).

Montaup noted the existence of additional planning uncertainties that do not as easily lend themselves to the type of quantification applied to the uncertainties discussed above (id. at 25). Montaup stated that events such as fuel interruptions and new regulatory policies are more difficult to model, but are considered in a qualitative manner during final plan selection (id.). Montaup did not provide methodological details or results of qualitative uncertainty analyses conducted by Montaup.

iii. Database Expansion Model

Mr. Kirby indicated that Montaup initially analyzed over 62,000 "scenarios" in the development of a generic expansion plan (Tr. 2, at 70).[54] Montaup stated that full evaluation of all scenarios using production cost simulation would require a prohibitive amount of time and computer resources (Exh. EUASC-1, Vol. 2, at 29). Instead, Montaup indicated that it used a database expansion model created by Production Technologies, Inc. to more easily estimate the key attributes of each scenario (id. at 29-30; Tr. 2, at 71).

The database expansion program estimated the performance of scenarios against the key system attributes through use of a mathematical interpolation procedure (Exh. EUASC-1, Vol. 2, at 29). Montaup stated that case studies of the database expansion program demonstrated interpolation errors of less than five percent (id. at 30).

Montaup stated that Montaup's database expansion program used the output from a limited number of production cost runs to define the parameters of a group of system attributes (Tr. 2, at 71). Montaup did not provide specific information regarding parameters established for each system attribute addressed in the analysis.

Montaup stated that it used the database expansion program and a process of elimination to narrow down the original 385 plans to a discrete number of plans to be fully

54 Combining the foregoing items -- 385 potentially viable plans and 162 futures -- resulted in 62,370 "scenarios" for consideration.

evaluated in the production cost analysis (id. at 72). Mr. Kirby stated that plans that performed poorly against the system attributes were eliminated (id. at 66). Montaup did not provide information specifying which key system attributes were tested in the process of elimination. Similarly, Montaup did not furnish documentation of the performance of tested scenarios against those specific attributes.

iv. Production Cost Analysis

Montaup indicated that its evaluation process entailed analysis of the interactions among candidate resource options and existing resources (id. at 2, 28). Montaup stated that it used the production cost model, UPLAN, to conduct that analysis (id. at 28-29; Exh. EFSC-D-16). Montaup indicated that separate runs of UPLAN calculated the Montaup system production costs and measures of various non-cost system attributes associated with each plan tested (Exh. EUASC-1, Vol. 2, at 29). Montaup stated that Montaup adds UPLAN outputs to demand-side costs and capital costs to calculate total system present worth of revenue requirements and a "cost per KWH" index (id.).

v. Selection of an Expansion Plan

Montaup indicated that choosing a course of action for expansion involved balancing a variety of system attributes, including production costs, system reliability, energy source diversity, and environmental impacts (id.). Montaup stated that these attributes are interrelated, and must be viewed as such when assessing system performance from the perspectives of society at large, ratepayers, and EUA shareholders (id. at 30).[55]

Montaup indicated that, for each future – or combination of planning uncertainties – the potentially viable plans that met the criterion of achieving balanced, nearly-optimal

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[55] Montaup noted that some system performance attributes conflict, and in some cases, these attributes are actually inversely related (Exh. EUASC-1, Vol. 2, at 30). Montaup indicated that, in choosing a future resource plan under these circumstances, it is necessary to conduct a trade-off analysis through which Montaup strives to adopt plans which "tend to be among the better options with respect to all the attributes, as opposed to being necessarily the best with respect to any one attribute" (id.).

attribute values were grouped into "decision sets" (id.). Montaup then searched through decision sets to identify those plans that were in the greatest number of decision sets (id.). Montaup indicated that, in theory, a plan that is a member of every decision set would be an optimal, no-risk plan (id.).

After identifying the plans that were members of the largest range of decision sets, Montaup stated that it conducted additional examinations to ascertain why identified plans did not perform well under specific combinations of uncertainties (id.). This examination lead to final selection of a plan (id.).[56] Montaup's generic plan ultimately included the selection a 100 MW gas-fired combined cycle generating unit to be added in the year 2000, and the addition of nearly 385 Gwh per year in DSM savings (id. at 32-33).[57,58,59]

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56 Montaup stated that final plan selection may include devising an additional strategy or plan to hedge against potential adverse outcomes, furthering Montaup's risk minimization objective (EUASC-1, Vol. 2, at 30, 31). Montaup noted that implementation of DSM resources may be viewed as an effective hedging strategy, since the need for new investment in supply-side resources may be deferred (id. at 31). Such a deferral can mitigate the cost and availability risks associated with investments in supply-side resources (id.).

57 Montaup stated that the actual characteristics of the next supply-side addition will be dependent upon the successful implementation and operation of committed and existing resources, as well as load growth and fuel price outcomes (Exh. EUASC-1, Vol. 2, at 33). Montaup stressed the generic nature of this plan, and noted that precise characteristics of future resource additions would be subject to revisions and would be the result of a full, competitive RFP process (id.).

58 Montaup noted that conservation was a component of nearly all of the best potentially viable plans, and that these plans exhibited considerable resiliency against cost uncertainties (Exh. EUASC-1, Vol. 2, at 32).

59 Montaup indicated that the process used to evaluate future, purchased resources identified through issuance of RFPs would be similar, but simpler than the process used to evaluate generic resources. (Exh. EUASC-1, Vol. 2, at 31). Montaup stated that the number of distinct plans to analyze for optimal attribute values is likely to be considerably fewer than the number of scenarios analyzed for the generic expansion plan, and that the reduced number of plans will obviate the need for much of the database expansion and the level of risk and uncertainty analysis conducted for the generic expansion plan (id.).

b. Cost

Montaup stated that one of its resource planning objectives is to provide energy consistent with efficient, safe, and environmentally compatible operation at the lowest practical cost to customers (Exh. EUASC-1, Vol. 2, at 1). As noted in Section III.D.1.b., supra, Montaup's planning process selects generating resource options on the basis of cost by screening and evaluating each option using a busbar cost screen, a database expansion program, and the production cost program, UPLAN. In this section, the Department reviews Montaup's incorporation of cost considerations in its evaluation of (1) generic, Montaup-sponsored generating and DSM resources compiled as part of Montaup's "generic expansion plan", and (2) specific supply- and demand-side resources purchased by Montaup from developers of QFs, IPPs, other utilities or their affiliates, and providers of DSM technologies and programs.

i. Company-sponsored Generating and DSM Resources

Montaup's methodology for incorporating cost considerations in its evaluation of generic, Montaup-sponsored generating and DSM resources compiled as part of Montaup's generic expansion plan exhibits several noteworthy strengths. Specifically, Montaup's resource evaluation framework is comprehensive in its treatment of critical planning uncertainties and its compilation of a vast array of potentially viable plans. The Department notes that Montaup's analysis of uncertainties contributes to a more complete evaluation of the cost-effectiveness of potential resources, and accounts for many of the key factors that are likely to have profound impacts on the cost of the energy resources provided by Montaup. Montaup's analysis of the cost performance of potential resources under multiple scenarios of load growth, fuel prices, capital costs, DSM costs, and DSM penetration encompasses a significant range of plausible assumptions. Further, Montaup's compilation of a potential resource into a substantial number of different combinations provides insights into the least-cost resource mix under a wide range of contingencies and uncertainties. In the past, the Siting Council has stated that for a supply plan to be truly least-cost, it must prove to be least-cost over a significant range of plausible assumptions. 1991 Nantucket Decision, 21 DOMSC at 297.

In addition, Montaup's use of the production cost model, UPLAN, is an appropriate means of comparing the production costs that would be incurred under alternate expansion plans. However, Montaup did not provide calculations of present worth of revenue requirements and cents per KWH indices, or information regarding the results of production cost runs.

In summary, Montaup's methodology for evaluating Montaup-sponsored generating and DSM resources, as presented in the filing currently before the Department, exhibits several noteworthy strengths. However, Montaup provided little or no documentation of critical aspects of the evaluation process as it applies to Montaup's cost objective. Accordingly, the Department makes no finding on whether Montaup's evaluation of Company-sponsored resources for the generic expansion plan adequately considers the objective of cost.

ii. Purchased Resources

As discussed in Section III.D.1.a.iii., supra, Montaup indicated that Montaup plans to issue supply- and demand-side RFPs as part of its resource identification and screening process only "when a need for additional resource capacity is identified." Montaup stated that the scoring systems applied to such an RFP in fact may be different from those systems used in the generic expansion plan. Therefore, the Department made no finding on whether Montaup has established that it has developed and applied appropriate criteria for screening purchased resources.

The Department notes that Montaup anticipates that the evaluation process applied to resources identified through the issuance of future RFPs will be similar to the process used to evaluate potentially viable generic expansion plans. The Department has made no finding on whether Montaup's evaluation of Company-sponsored resources for the generic expansion plan adequately considers least-cost planning objectives. Accordingly, the Department makes no finding on whether Montaup's process for evaluating resource options identified through future RFPs and purchased by Montaup, adequately considers the objective of cost.

iii. Conclusions on Cost

The Department has made no finding on whether Montaup's process for evaluating (1) generic, Montaup-sponsored generating and DSM resources compiled as part of Montaup's "generic expansion plan;" and (2) specific supply- and demand-side resources purchased by Montaup from developers of qualifying facilities QFs, independent power producers IPPs, other utilities or their affiliates, and providers of DSM technologies and programs adequately considers the objective of cost. Accordingly, the Department makes no finding on whether Montaup's process for evaluating resources adequately considers the objective of cost.

c. Diversity

An electric company may address diversity in a number of ways. In previous cases, electric companies have addressed diversity in terms of (1) types of fuel supply, (2) types of generation technology, and (3) whether resources are Company-owned or provided by third parties. 1991 Nantucket Decision, 21 DOMSC at 305; 1990 MMWEC Decision, 20 DOMSC at 87-89; 1989 MECo Decision, 18 DOMSC at 363-365.

The record in the instant case indicates that Montaup's resource planning process incorporated the ability to identify, screen and evaluate a diversity of generating technologies encompassing a plausible range of fuel types, duty types, capacity factors, and in-service dates. In addition, Montaup's planning process included the identification and screening of a broad range of DSM resources. Further, the record indicates that, when the projected date of capacity need approaches, Montaup plans to issue an all-resources RFP in an effort to elicit responses from third party sponsors of generating and DSM resources. Finally, Montaup included "flexibility and diversity in the resource portfolio to minimize operational and cost risks..." as one of its resource planning criteria (Exh. EUASC-1, Vol. 2, at 1).

However, the Department's ability to make a finding regarding Montaup's consideration of diversity in its planning process is limited by the same lack of documentation alluded to in Section II.D.2.b., supra. For example, the Department is unable to ascertain whether Montaup evaluated generating technologies encompassing a broad range of fuel types, duty types, capacity factors and in-service dates without documentation regarding the content of the potentially viable plans developed by Montaup. Similarly, Montaup did not provide information regarding the methods used to apply non-price weighting factors to system attributes – such as fuel source – that contribute to diversity. Accordingly, the Department makes no finding on whether Montaup's methodology for evaluating resource options adequately considers diversity.

d. Risk Minimization

An electric company's resource planning process may address risk in a number of ways. In previous cases, electric companies have addressed minimization of risk by means of: (1) incorporating multiple scenarios into their demand forecasts to address uncertainty in the need for new supplies; (2) formulating action plans to address supply contingencies; and (3) minimizing financial risk through transactions with third parties. 1991 Nantucket Decision, 21 DOMSC at 306; 1990 MMWEC Decision, 20 DOMSC at 88-91; 1989 MECo Decision, 18 DOMSC at 366-368; 1989 BECo Decision, 18 DOMSC at 271-272, 338-339.

The record in this case indicates that Montaup developed multiple peak demand scenarios in its analysis of uncertainties and developed action plans to address supply contingencies. The record also indicates that Montaup intends to issue RFPs to conduct transactions with third parties. Further, Montaup used a production costing model to evaluate the cost risks associated with potentially viable expansion plans. Accordingly, the Department finds that Montaup's methodology for evaluating resource options adequately considers minimization of risk.

e. Environmental Impacts

In previous decisions, the Siting Council has considered whether an electric Company has attributed environmental impacts or benefits to different resource options. 1991 Nantucket Decision, 21 DOMSC at 306-308; 1990 MMWEC Decision, 20 DOMSC at 93-95; 1989 MECo Decision, 18 DOMSC at 368-369; 1989 BECo Decision, 18 DOMSC at 238-239, 270.

Montaup included providing "...energy consistent with efficient, safe, and environmentally compatible operation..." as one of its resource planning criteria (Exh. EUASC-1, Vol. 2, at 1). The record in this case indicates that Montaup's supply screening process consisted, in part, of the ranking of potential generating resource options according to a number of non-price criteria, including environmental impacts (id. at 21) However, Montaup did not provide complete information regarding the methods used to apply environmental weighting factors to each of the identified generating technologies. The record in this case further indicates that Montaup included avoided environmental costs in its screening of potential DSM resources (id. at 22). However, Montaup did not provide documentation of the actual values attached to these avoided environmental costs.

The Department notes that Montaup's resource planning process incorporates the recognition that environmental impacts play a significant role in choosing potential resource additions. However, Montaup has failed to provide documentation of the methodology used to quantify, or otherwise acknowledge environmental impacts. Accordingly, the Department makes no finding on whether Montaup's methodology for evaluating resource options adequately considers environmental impacts.

f. Conclusions on the Resource Evaluation Process

The Department has made no finding on whether Montaup adequately incorporates consideration of cost, diversity, and environmental impacts in its supply planning process. The Department has found, for the purposes of this review, that Montaup has established that it adequately incorporates consideration of risk minimization in its supply planning process.

Based on the foregoing, the Department makes no finding on whether Montaup has established that it (1) developed a resource evaluation process that fully evaluates all resource options, including the treatment of all resource options on an equal footing, and (2) applied its resource evaluation process to all resource options.

3. Conclusions on Least Cost Supply

The Department has found that Montaup has identified a reasonable range of resource options. The Department has made no finding on whether Montaup has established that it (1) developed a resource evaluation process that fully evaluates all resource options, including the treatment of all resource options on an equal footing, and (2) applied its resource evaluation process to all resource options.

Accordingly, the Department makes no finding on whether Montaup has established that its supply plan ensures a least-cost energy supply. The Department notes that its lack of ability to make findings on the Company's least-cost planning process is due, in large part to the fact that the Company has not actually implemented its resource solicitation process.

E. Conclusions on the Supply Plan

The Department has found that Montaup has adequate resources to meet projected requirements throughout the forecast period. The Department has made no finding on whether Montaup's supply planning process ensures a least-cost energy supply. The Department notes that Montaup has incorporated significant improvements into its newly-developed least-cost resource planning process since the previous review. Montaup's resource planning process exhibits notable strengths and entails (1) a determination of capacity and energy requirements, (2) identification and screening of resource options, (3) creation of potentially viable option sets from highly ranked individual resources, (4) analysis of the interactions among resource options and existing resources, and (5) choosing the mix of resources which best balances a range of performance attributes Montaup is to be strongly commended for developing an enhanced resource planning process that entails the analysis of a vast range possible future scenarios. However, the Department notes that a weakness of Montaup's resource planning process entails the lack of documentation of key elements of the planning process. We expect that the Company will provide complete documentation of key supply planning elements in future filings before the Department. The strengths of Montaup's supply planning process clearly outweigh this weaknesses. Accordingly, The Department hereby APPROVES Montaup's 1992 supply plan.

IV. DECISION

The Department hereby APPROVES the 1992 demand forecast of Eastern Edison Company and APPROVES the 1992 supply plan Montaup Electric Company.

TABLE 1

EASTERN UTILITIES ASSOCIATES
History and Unadjusted* Forecast of Eastern Edison's Energy Requirements
and Summer Peak Demand

Year	Energy Requirements (GWH)	% Growth	Summer Peak (MW)	% Growth
1978	2,009	-----	365.5	-----
1979	2,043	1.7	374.1	2.4
1980	2,034	-0.4	377.1	0.8
1981	2,004	-1.5	349.7	-7.3
1982	1,994	-0.5	390.4	11.6
1983	2,100	5.3	401.4	2.8
1984	2,177	3.7	415.8	3.6
1985	2,222	2.1	433.7	4.3
1986	2,327	4.7	403.3	-7.0
1987	2,448	5.2	461.9	14.5
1988	2,586	5.6	501.6	8.6
1989	2,642	2.2	506.3	0.9
1990	2,581	-2.3	488.5	-3.5
1991	2,543	-1.5	500.5	2.5
1992	2,598	2.2	495.2	-1.1
1993	2,649	2.0	507.5	2.5
1994	2,711	2.3	520.6	2.6
1995	2,771	2.2	533.4	2.5
1996	2,837	2.4	545.9	2.3
1997	2,904	2.4	561.6	2.9
1998	2,970	2.3	575.7	2.5
1999	3,042	2.4	591.1	2.7
2000	3,118	2.5	605.6	2.5
2001	3,183	2.1	621.4	2.6

Note: * Unadjusted for projected DSM savings.
Source: Exh. EUASC-1, Vol. 3, at C-11.

TABLE 2

EASTERN UTILITIES ASSOCIATES
Unadjusted* Forecast of Eastern Edison's Total Energy Output Requirements
(GWH)

Year	Residential	Commercial	Industrial	Streetlighting	Losses and Internal Use	Total Energy Requirements
1992	1,039	1,128	301	15	115	2,598
1993	1,058	1,152	307	15	117	2,649
1994	1,078	1,186	312	15	120	2,711
1995	1,097	1,219	317	15	123	2,771
1996	1,116	1,257	324	15	125	2,837
1997	1,138	1,293	329	15	128	2,904
1998	1,158	1,328	337	15	131	2,970
1999	1,182	1,366	344	15	134	3,042
2000	1,207	1,407	351	15	137	3,118
2001	1,229	1,442	358	15	140	3,183

Note: * Unadjusted for projected DSM savings.
Source: Exh. EUASC-1, Vol 3, at C-8.

TABLE 3

EASTERN UTILITIES ASSOCIATES
Short-Run Supply Adequacy, Base Case
Summer Peak Loads (MW)

Year	Capability Responsibility	Existing Capability	Base Case Surplus	%
1993	1081.2	1263.3	182.1	16.8
1994	1071.6	1263.4	191.8	17.9
1995	1072.0	1223.4	151.4	14.1
1996	1097.1	1276.7	197.6	18.3

Notes: (1) Montaup stated that its Capability Responsibility consisted of its forecasted peak loads and required reserves. Montaup derived its required reserves from NEPOOL's November, 1990 Objective Capability Report. Montaup stated that this NEPOOL document was the most current set of data regarding reserve requirements.

(2) Existing Capability includes existing and planned DSM, ownership units (full, joint, and equity), short-term purchases, long-term purchases, and new supply-side additions (Exh. EUASC-1, Vol. 2, at 36).

Source: Exhs. EFSC-RR-2; EUASC-1, Vol. 2, at 2, 36

TABLE 4

EASTERN UTILITIES ASSOCIATES
Short-Run Supply Adequacy, Contingency Case
Summer Peak Loads (MW)

Year	Capability Responsibility	Existing Capability	Adjustment	Surplus	%
1993	1081.2	1263.3	(52.9)	129.2	11.9
1994	1071.6	1263.4	(58.6)	133.2	17.9
1995	1072.0	1223.4	(63.1)	88.3	8.2
1996	1097.1	1276.7	(98.9)	98.7	9.2

Notes: Adjustment column represents reductions in resources due to the combined effects of uncertainty factors.

Source: Exhs. EFSC-RR-3; EUASC-1, Vol. 2, at 36.